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Modelling of Demand Response in Distribution Systems

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To Alexandra, Liam, Lykke and Ebbe

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Abstract

Large scale integration of plug-in electric vehicles (PEVs) and intermittent renewable energy sources, such as solar PV and wind power, could affect the way in which the power system is planned, operated and controlled. In such systems, it could be desirable to utilize the flexibility of the demand, i.e. demand response (DR), to help maintain the balance between the supply and the demand, and to avoid or defer grid reinforcements. One approach to promote DR could be through the use of hourly electricity tariffs based on electricity prices on the day-ahead market. In this context, a PEV could be seen as a flexible load, due to the possibility to schedule its charging.

The main purposes of this thesis are to investigate: the impact of PEVs on distribution systems; strategies to schedule the charging and other flexible loads; customers' benefits of scheduling their loads according to these strategies; and the influence of different network tariffs in combination with hourly electricity pricing. Furthermore, the possible synergy between DR and wind power is investigated.

The results show a large difference in possible PEV penetration levels between the investigated areas. The distribution system in the commercial area investigated could handle a full PEV penetration without any overloading while the residential distribution system was experiencing transformer overloading even without PEVs. By scheduling the charging in order to minimize the losses, the residential distribution system all cars could be replaced by PEVs without increased peak demand. If instead the day-ahead market prices were used as scheduling signals, 24% of the cars could be replaced by PEVs without increased peak demand.

By considering other flexible loads, such as electric space-heating, the residential distribution system would experience a decreased peak demand, if up to 25% of the customers were responsive to day-ahead market prices and if an energy based network tariff was used. For higher shares of responsive customers, the peak demand was increased, due to an increased coincident factor. By using a power based network tariff instead, the peak demand could be reduced even if all customers were responsive. From a customer perspective, a cost reduction of up to approximately 10% could be achieved by actively managing the flexible loads. With PEVs available, a cost reduction of up to 13% could be reached. For customers with large variations in their demand, a power based network tariff would be preferable, while for other customers, the difference in benefits between the network tariffs was found to be small.

The possible economic benefit for wind power producers in power systems with DR, was found to be slightly decreased for several price-areas, although the total benefit of all wind power producers was increased. From a customer perspective, the interaction between DR and wind power could lead to a cost reduction for responsive customers in some areas whereas the cost was increased for responsive customers in other areas.

Keywords: Electrical distribution system; demand response; Plug-in Electric Vehicle (PEV); space-heating; thermal energy storage; wind power.

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At last, I would like to send my thoughts to my family and friends, thanks for your support, consideration, patience and for enriching my life.

David Steen
Gothenburg,
Sweden, 2014

List of publications

This thesis is based on the work contained in the following papers:

Papers related to PEVs:

[I] Saman Babaei, David Steen, Le Tuan, Ola Carlson and Lina Bertling, "Effects of Plug-in Electric Vehicles on Distribution Systems: The Real Case of Gothenburg," *IEEE PES Conference on Innovative Smart Grid Technologies Europe*, Gothenburg, Sweden, October 10-13, 2010.

[II] David Steen, Le Tuan, Miguel Ortega-Vazquez Ola Carlson, Lina Bertling and Viktoria Neimane, "Scheduling Charging of Electric Vehicles for Optimal Distribution Systems Planning and Operation," *CIRED*, Frankfurt, Germany, June 6-9, 2011.

[III] David Steen, Le Tuan, Ola Carlson and Lina Bertling, "Assessment of Electric Vehicle Charging Scenarios Based on Demographical Data," *IEEE Transactions on Smart Grid, vol.3, no.3, pp.1457-1468,* September, 2012.

Papers related to PEVs and/or other flexible loads:

[IV] David Steen, Salem Al-Yami, Le Tuan, Ola Carlson and Lina Bertling, "Optimal Load Management of Electric Heating and PEV Loads in a Residential Distribution System in Sweden," *IEEE PES Conference on Innovative Smart Grid Technologies Europe*, Manchester, UK, December 5-7, 2011.

[V] David Steen, Le Tuan, Ola Carlson and Lina Bertling Tjernberg, "Evaluating the customers' benefits of hourly pricing based on day-ahead spot market," *CIRED*, Stockholm, Sweden June 10-13, 2013.

[VI] David Steen, Le Tuan and Ola Carlson, "Effects of Network Tariffs on Residential Distribution Systems and Price-Responsive Customers under Hourly Electricity Pricing," *Submitted to IEEE Transactions on Smart Grid.*

Paper related to demand response and wind power:

[VII] David Steen, Pavan Balram, Le Tuan, Lina Reichenberg and Lina Bertling-Tjernberg, "Impact Assessment of Wind Power and Demand Side Management on Spot Market Prices," *IEEE PES Conference on Innovative Smart Grid Technologies Europe*, Istanbul, Turkey, October 12-15, 2014.

Paper related to thermal energy storage:

[VIII] David Steen, Michael Stadler, Gonçalo Cardoso, Markus Groissböck, Nicholas DeForest and Chris Marnay "Modeling of Thermal Storage Systems in MILP Distributed Energy Resource Models," *Accepted for publication in Applied Energy.*

In addition to the above mentioned papers, following publications have been produced during the course of this PhD project.

[IX] Lina Bertling, Ola Carlson, Sonja Lundmark and David Steen, "Integration of Plug-in Hybrid Electric Vehicles and Electric Vehicles - Experience From Sweden," *IEEE Power and Energy Society General Meeting*, Minneapolis, Minnesota, USA, July 25-29, 2010.

[X] David Steen, Le Tuan and Lina Bertling Tjernberg, "Price-Based Demand-Side Management For Reducing Peak Demand In Electrical Distribution Systems - With Examples From Gothenburg," *Nordic Electricity Distribution and Asset management Conference (NORDAC)*, Aalto, Finland, September 10-11, 2012.

[XI] Saeed Rahimi, David Steen, Stefano Massucco, Federico Silvestro and Kun Zhu, "Evaluating the Use of DMS advanced Functions to Reduce the Impact of Plug-In Electric Vehicles on Distribution Systems," *EVTeC and APE*, Yokohama, Japan, 2014.

[XII] Christopher Saunders, Lisa Göransson, David Steen, Sten Karlsson and Marina Papatriantafilou, "Electric Vehicles and Intermittent Electricity Production," *System Perspectives on Electromobility,* ISBN: 978-91-980973-9-9, Chalmers University of Technology, 2013.

[XIII] David Steen, Joel Goop, Lisa Göransson, Shemsedin Nursbo, Magnus Brolin, "Challenges of Integrating Solar and Wind into the Electricity Grid," *System Perspectives on Renewable Power,* ISBN: 978-91-980974-0-5, Chalmers University of Technology, 2014.

[XIV] Emil Nyholm, David Steen, "Can Demand Response Mitigate the Impact of Intermittent Supply?" *System Perspectives on Renewable Power,* ISBN: 978-91-980974-0-5, Chalmers University of Technology, 2014.

Contents

List of abbreviations

This section presents the abbreviations used in the thesis.

RES	renewable energy sources
PV	photo-voltaic
PEV	plug-in electric vehicle
DR	demand response
HWB	hot water boiler
TES	thermal energy storage
DER-CAM	distributed energy resources customer adoption model
TOU	time of use
CPP	critical peak pricing
DLC	direct load control
ICS	interuptible/curtailable service
RTP	real time pricing
LMP	locational marginal price
D-LMP	distributed locational marginal price
DSO	distribution system operator
V2G	vehicle to grid
μCHP	micro combined heat and power
MILP	mixed integer linear programming
GAMS	general algebraic modelling system
HP	heat pump
EBT	energy based network tariff
PBT	power based network tariff

MPT monthly power based network tariff

DPT daily power based network tariff

AAP average area price

Chapter 1

Introduction

1.1 Background

Since the industrial revolution the global energy consumption has steadily increased in hand with the economic growth. In 2013, the electricity consumption stood for about 15% of the global primary energy consumption [1]. Although a majority of the electricity is produced by fossil fuels and nuclear power, investments in renewable energy sources (RES) has steadily increased. In terms of generation capacity, investments in RES in 2013 were greater than investments in fossil based capacity, mainly driven by investments in hydro power, solar photovoltaic (PV) and wind power [2]. In the European Union, the renewable share reached 72% of the capacity investments in 2013, and the total installed RES capacity corresponds to almost one third of the total installed capacity [2, 3].

Integrating large shares of wind power and solar PV into the existing power system would affect the way the power system is operated, since these electricity sources only produce electricity under certain conditions, i.e. when it is windy or sunny. Traditionally, the balance between demand and production has been maintained by using flexible generating units that follow the diurnal variations in electricity consumption. With increasing shares of wind power and solar PV, variations in production must also be considered resulting in higher demand on the flexibility for the remaining generation units. Furthermore, due to the low running cost of RES, these sources could outcompete some of the existing generation capacity, resulting in even less flexible generation capacity [4].

At the same time, the interest for plug-in electric vehicles (PEVs), i.e. battery electric vehicles and plug-in hybrid electric vehicles, is increasing. Although the number of PEVs available today is limited, they are becoming increasingly popular as more car models enter the market and the awareness of PEVs increases. In Norway and Netherlands about 5-6% of the cars sold in 2013 were PEVs [5], and in the first half year of 2014 almost 13% of the cars sold in Norway were PEVs [6]. Forecast predicts a slow penetration rate of PEVs, e.g. 4% of the vehicles in EU would be PEVs in 2030 and 8% in 2050 [7]. The Norwegian case shows that, with strong incentives, the penetration of PEVs could grow at a much faster pace. As for RES integration, charging of PEVs would affect the power system. If the charging is conducted during peak load hours, the additional demand from PEVs could result in a need for grid expansion, both in the transmission and distribution system [8–10].

Since cars are generally parked for long periods of time, the charging could be shifted in time without affecting the comfort of the user. By utilizing this flexibility, PEVs can be seen as a potential resource to improve the power system conditions rather than as a challenge. Rescheduling the demand in time is commonly referred to as demand response (DR) and could be used to avoid investments in new flexible generation capacity and expensive grid expansions. In addition to PEVs, existing loads such as electric space-heating/cooling and dishwashers could be utilized. However, these loads could only be shifted for a limited number of hours. Hence DR could mainly be used to improve the operation of the power system over a short time range, e.g. on a daily basis. For longer time-periods other alternatives, such as large scale energy storage, e.g. pumped hydro or compressed air, would be necessary.

To achieve an effective scheduling of the demand, it is vital that there exist incentives for customers to reschedule their electricity usage, and that the incentives actually reflect the conditions in the power system. From a distribution system perspective, that would generally be to reduce the peak demand, or for distribution systems with a high share of distributed generation, to reduce the exported electricity. From a transmission system perspective the aim would be similar. However, both improving system conditions locally and nationally may be conflicting in some cases. For a heavily constrained distribution system, reducing the peak demand may be most vital, whereas the objective from a national perspective might be to increase the demand during the same hours due to a high production of electricity from RES. Hence it is important to formulate the DR programs to cope with both local and regional/national conditions.

1.2 Aims and main contributions of the work

The overall aim of this thesis is to investigate the possible benefits and adverse impacts from DR in the electrical distribution system with high shares of PEVs. The focus has been on the benefits for the distribution system and for price-responsive residential end-use customers. Although a variety of different DR approaches exist, the focus has been on the currently available method in Sweden where customers are charged with an hourly electricity price based on the Nordic day-ahead electricity market, Nordpool spot [11]. The possible impacts of DR on day-ahead markets with high shares of wind power have also been investigated.

To address this, e.g. the impact of DR on distribution system with high share of PEVs and on day-ahead markets with high shares of wind power, it is vital to know the available flexibility in the electricity demand, as well as the charge pattern of PEVs and generation pattern of wind power. In this thesis the generation pattern from wind power is based on existing work and the focus has been on modelling the flexible loads and the PEVs.

A part of the thesis relates to thermal energy storage (TES) modelling for investment decisions.

The main contributions of this thesis can be summarized as follows:

- A methodology to evaluate the charge pattern and flexibility of PEVs, based on vehicle statistics and demographical data.

- A model to estimate and schedule the available flexible demand in residential houses.
- A methodology to evaluate the effects of different network tariffs on customers' incentive to schedule their flexible demand and its consequential effect on the distribution system.
- A methodology to assess the possible mutual benefits for wind power producers and price-responsive customers.
- A model of a TES in the investment and planning software *distributed energy resource customer adoption model* (DER-CAM).

The developed scheduling model has been used in a case study of a real distribution system located in Gothenburg, Sweden. The effect on the distribution system was studied using an optimal power flow model, with the focus on steady state conditions, such as power capacity limitations and steady state voltage performance.

1.3 Outline of this thesis

This thesis is organized as a summary of the work presented in the 8 appended papers. The structure of the thesis is:

Chapter 1 This chapter provides a general background to the topics of DR and PEVs. In addition, the aims and main contributions of the thesis are provided.

Chapter 2 DR and PEVs have been extensively studied during the last decade. This chapter aims to present the current status in the academia, related to DR, PEVs and TES.

Chapter 3 This chapter presents an overview of the research approaches and models developed in this thesis. A more detailed description can be found in the appended papers.

Chapter 4 Due to space restrictions on the appended papers, they have focused on the models and methods developed, hence only the key results are highlighted. This chapter focuses on the results from the papers and includes an extended discussion of the results.

Chapter 5 In the final chapter, the main conclusions from this thesis are presented together with some possible ideas for future work.

Chapter 2

Related work

This chapter provides an introduction to the field of PEVs, DR and TES, and an overview of the current practice and the research conducted within this field. Also, the motivation and scope for this thesis have been identified.

2.1 Demand response

DR is about providing electricity end-use customers with incentives so that they can schedule their loads in such a way that the operation and cost of the power system is improved [12]. The concept has been used for several decades, but has evolved in recent years, mainly due to the introduction of renewable energy sources, ageing assets and advances in smart grid technologies [13]. Traditionally, DR programs have been designed for emergency situations, e.g. when a power plant is disconnected due to failure, or to reduce the peak demand to avoid need for investments in grid reinforcement and new peak power plants for power systems operated close to their limits. These approaches are often referred to as valley filling or peak shaving. However, in systems with high shares of wind power and solar PV it could also be desirable to shift demand to hours with high electricity production from RES, although the peak power is increased, as long as the system capacity is sufficient. An example of this is presented in Fig. 2.1. Hence, for a DR program to be effective it is important that it reflects the actual conditions in the power system. Below, some of the available DR programs today are presented and discussed from this perspective.

Time of use Tariff (TOU) - One common approach for residential customers is the TOU which is available in several countries, e.g. USA, UK, Italy and Spain [15, 16]. The main principle is to offer time-differentiated electricity prices to the end-use customers, usually two or three predefined price levels per day, i.e. on-peak and off-peak tariffs. Hence, the customers would have incentives to shift their flexible loads from hours with high demand to hours with lower demand. In a traditional power system with predictable consumption and production patterns, this tariff could be effective; however the structure of the tariff is too static to capture the conditions in a power system with a large share of RES [17].

Critical Peak Pricing (CPP) - This program offers customers reduced electricity rates under normal circumstances while the electricity retailer has the

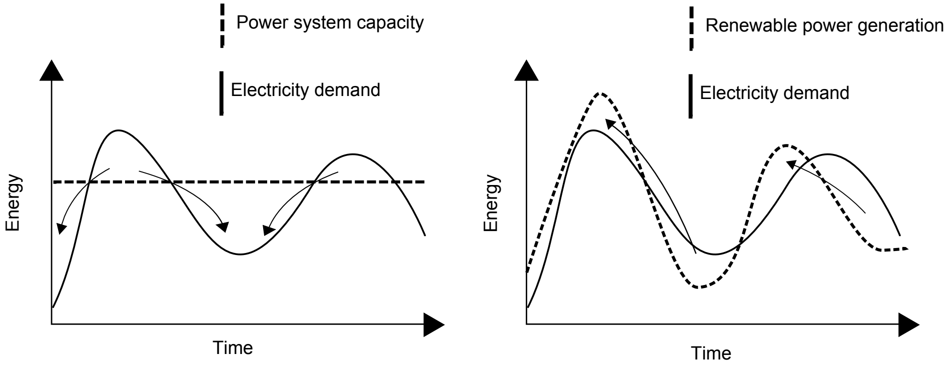


Figure 2.1: Traditional DR (left) and DR for a system with high share of RES (right) [14].

possibility to increase the electricity rates for some hours every year when the transmission/distribution system is congested. One disadvantage with CPP is that the number of hours available to apply CPP is limited during a year [17]. Hence, it could not be used on a regular basis to improve the overall system performance.

Direct Load Control (DLC) - The idea of DLC is to compensate customers economically if they in return offer the DSO the possibility to remotely turn off some of their electrical loads, e.g. domestic hot water boilers or air-conditioners, during contingencies in the power system [18]. Although this method is easy to implement, e.g. no advanced metering system is needed, there are some drawbacks. For example, if no measurements are conducted, all customers participating in the program are compensated even if the device was not in use before the contingency [19]. Additionally, when the load is connected again, the power demand could be increased due to the cold load pick-up and additional measures such as controlled reconnection may be needed [20]. DLC would have a positive effect on the power system, in terms of reduced need for reinforcements and investments, but they do not improve system performance under normal operation. Although it is not common today, the program could also be offered by an aggregator that uses the customers' flexibility, to provide ancillary services [21].

Interruptible/Curtailable Service (ICS) - Similar to DLC, the ICS is based on curtailment of electrical loads when the power system is under stress [17]. Unlike DLC, the loads are not remotely controlled and ICSs are traditionally only offered to large industrial customers [22]. Participants are offered a discount on the retail tariff but, if they fail to provide the load reduction they signed up for, they are penalized [22]. Similar to DLC, this tariff does not improve system performance under normal operation.

Power tariffs - The idea of power tariffs, or demand charges, is to provide incentives for customers to reduce their peak demand by increasing the network tariff as their peak demand increases. Traditionally, power tariffs are based on the monthly peak demand but could be based on shorter time periods as well [17]. This tariff would generally result in an overall peak shaving in the power system but does not provide any incentives to schedule the demand to follow the electricity production. Moreover, the peak demand of a single customer does not necessarily increase the total peak demand in the power system since the customer's peak may occur at a different time compared to the total peak in the power system.

Real Time Pricing (RTP) - The main idea of a RTP program is to provide customers with an electricity price that reflects the actual conditions in the power system. One important aspect regarding the design of a RTP scheme is the time difference between the announcement of the price to the customers and the actual consumption. A long time lag, e.g. using day-ahead price, which has been most commonly used, would result in a price that less accurately reflects the power system conditions [17]. It may also result in increased need for balancing power, if the scheduled demand is not considered in the day-ahead market [23]. A shorter time lag, e.g. based on the intraday market, would result in better reflection of the demand/supply but make it more difficult for the customers to plan their electricity consumption [17]. The RTP can be calculated based on the area price, as in the Nordic power market [11], or on the locational marginal price (LMP), as in the New Zealand power market and some markets in USA, although the RTP is not offered to all customers in all markets [24, 25].

Since the market price of electricity depends both on the available production and on the consumption, the volatility in the electricity price could increase with increased electricity production from intermittent energy sources. This has for example, been observed in power systems with a high share of wind power where the electricity prices have even been negative [26]. Hence, RTP would likely be the program that best would support the integration of RES. RTP has been studied extensively and different approaches have been proposed, both regarding the design of the tariff but also regarding how to assess the demand side flexibility.

2.1.1 Approaches to model demand flexibility

Two common approaches used to assess the potential of DR are based either on price elasticity or on models of the individual appliances. The price elasticity approach considers electricity as the same as any other commodity, where the electricity demand would change with the electricity price [27]. This is usually used for studies on a system level, e.g. to investigate the influence of DR for a system with a high level of RES [28, 29], but could also be used for studies on lower levels such as distribution systems [27]. While price elasticity models provide insights on the possible impact of DR on the power system, it is difficult to use this approach to control the individual loads, or to investigate the benefit on a customer level. To achieve this, the actual usage of the flexible appliances must be found and a more detailed model of their flexibility would be needed. The appliances that could be considered flexible would depend on how the customers' comfort would be affected but also on the time the load is shifted. For a short time period, e.g. minutes, refrigerators and freezers could be considered flexible and provide ancillary services although they are not suitable on a longer time horizon [4]. Other loads that could be considered flexible in the residential sector are electric space-heating and cooling, domestic hot water boilers (HWB), dishwashers and laundry machines [30–32].

By allowing some variations in the indoor temperature, electric space-heating could provide a significant amount of DR in countries with cold climates, such as Sweden [33]. To assess this potential, a model of the building must be considered.

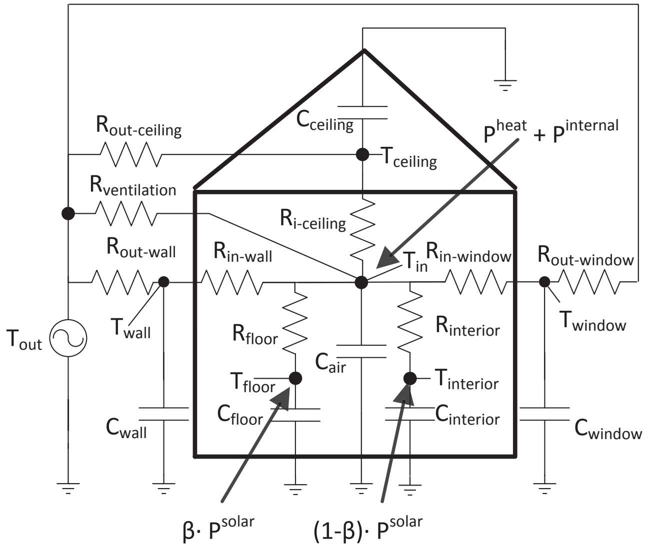


Figure 2.2: A schematic circuit diagram of a lumped capacity model of a building.

A common approach is to model the building as a lumped capacity model [34–37]. Although the accuracy of the model is increased for a second order system compared with a first order system [34], first order systems are usually used in studies assessing the potential for DR in buildings, e.g. [30, 38, 39]. Fig. 2.2 presents a simplified lumped capacity model based on a first order dynamic system.

Similarly, the usage of a HWB could be shifted in time if a hot water tank is available. The potential load shifting capability depends on the size of the hot water tank and on the installed heat capacity. In [39], the HWB is modelled and used as an energy storage to schedule the demand in order to reduce the energy cost. The model does not consider any energy losses apart from charge and discharge efficiency. By considering conduction losses through the walls of the hot water tank, the demand response potential could be more accurately determined and reduce the risk for inconvenience for the customers [31].

By considering historical usage pattern for dishwashers, laundry machines and cloth dryers the DR potential could be assessed [32, 40]. In [41], the starting time and energy use of different appliances were used to assess the potential for DR on a national level.

2.1.2 Impact of DR on the electric power system and the electric power market

A number of studies on RTP have been conducted in different countries, e.g. Portugal [22], Spain [42], USA [43], Singapore [44] and in the Nordic countries [45]. These studies indicate that RTP could have a significant impact on the peak demand, even for power systems with low price elasticity in the demand. Furthermore, these studies assume a short time lag between the price announcement and the implemented price or some kind of feedback from the customer. The feedback could be for example, that customers bid on the spot market, either on their own or by a representative agent [43], so that equilibrium between demand and supply could be reached without increasing the need for balancing power.

As previously discussed, RTP could either be calculated as an area price or a LMP and reflects both the available generation and the power system conditions within a price area or a node. The LMP would better reflect the power system conditions since the price is generally calculated for smaller areas, i.e. the area connected to each LMP node. Still, each node serves several customers with a diverse consumption and production pattern, e.g. the New Zealand power market serves almost 2 million customers and consists of about 250 nodes [24]. Hence, LMP may not appropriately reflect the actual conditions within a distribution system. To reflect these conditions, distributed LMP (D-LMP) could be effective [46,47]. Such pricing schemes would increase the benefit for DSOs but may on the other hand be difficult to implement due to equality consideration and legislation.

In Sweden, RTP based on the Nordic day-ahead spot market is a possible pricing option for electricity end-use customers [48]. The electricity price is announced 12-36 hours in advance and price-responsive customers could schedule their demand without participating directly in the market. Hence, the retailer needs to estimate how their price-responsive customers are scheduling their demand. For low participation levels this could be handled by the retailer, since the demand flexibility would have a limited impact on the price formulation [23]. However, for higher participation levels it could become difficult to estimate the demand, resulting in increased trading on the intraday and balancing market [23]. The importance of bidding the flexible demand into the day-ahead market is also emphasized in [49].

2.1.3 Customers' benefit of DR

The possible benefits for customers who actively schedule their demand according to the RTP would depend on the market. In a market with high price volatility, the possible benefits could be higher compared with a market with low price volatility. However, the number of price-responsive customers could also affect the possible benefit, since a large number of customers could reduce the price volatility on the market [23]. In addition, if the electricity price is affected by the scheduled load, e.g. reduced price peaks, non-responsive customers could also benefit from the changes in the electricity price [23].

According to [23], the possible cost reduction achieved by customers that schedule their electric space-heating, could be as much as 47% when a small share of the customers are responsive, while the possible savings were reduced as more customers becomes responsive.

In [32], dishwashers, laundry and drying machines were considered flexible and shifted according to the day-ahead market prices to reduce the electricity cost for customers. On average the cost reduction was found to be €5.6/year.

2.2 Plug-in electric vehicles

The first PEVs were designed over a century ago and were, at the beginning of the 20th century, more common than gasoline cars in America [50]. However, the PEV was outcompeted by the gasoline car, mainly due to the long charging time, limited range and top speed and in combination with improvements of the gasoline car. Today, interest in PEVs has increased primarily due to legislation, environmental concerns and the issue of oil dependence. The major concerns regarding PEVs still involve short range but also high cost and access to charging infrastructure [51]. The main reasons for the high cost are due to the battery and, for the plug-in hybrid electric vehicles, the increased complexity of the drive train [51]. As the development and production volumes of batteries increase, it is assumed that the battery cost per kWh will decrease, resulting in lower cost and/or longer driving ranges [51]. The infrastructures for charging PEVs are being expanded in several cities, e.g. in London, Singapore, and Los Angeles, both by local energy companies, PEV producers and by new market players [52]. Some countries have initiated governmental programs to promote PEVs by developing a charge infrastructure [52].

Although PEVs have a lengthy history, they may be regarded as a relatively new area of research, especially from an electrical power system perspective. Since vehicle design and batteries have been seen as the major concerns regarding PEVs, a large share of the research has been concentrating on these topics.

One of the first papers published on the impact on the power system due to PEVs was [53], published in 1983. The study investigated how load management of PEVs could lower peak power in the power system. Other studies performed at that time, such as [54], stated that to avoid increased peaks in the power system the charging might need to be distributed to off-peak periods. However, it would take until the early 2000´s before the topic attracted greater academic interest. Below, the reader will find a short review of the literature published regarding modelling of PEVs, its impacts on the power system and approaches to minimize the impacts, both on a national and a local level.

2.2.1 Approaches to model PEVs

The impact of PEVs on the power system depends on a number of parameters, such as usage patter, charge power and number of PEVs etc. Studies investigating the impact of PEVs on a national level usually present the number of PEVs as a share of the total number of vehicles in the country, e.g. in [10, 55, 56]. On a local level this could be more complicated since the number of vehicles varies within different areas. A common approach is to estimate the number of vehicles within an area based on the number of household [9].

All PEVs would not be used simultaneously and hence it is not likely that all PEVs would be charged at the same time. By considering vehicle usage pattern, information such as driving distance and driving pattern, i.e. start and stop times, could be obtained. The driving pattern is also an important parameter when investigating different charge control strategies since it can be used to obtain the possible parking time. Since only a limited number of PEVs is available today, reliable data on the actual drive pattern for PEVs is limited. Instead, PEVs are commonly assumed to be used in similar fashion to conventional vehicles [57, 58]. Hence, national travel surveys could be used to obtain the usage pattern.

All vehicles are however, not used in the same way, and the driving distances would vary among the vehicles. One approach that could be used to capture this could be to use stochastic modelling [57–59]. Furthermore, since vehicles are mainly used for transportation, they will not be located at the same location during the entire day. With a developed charge infrastructure, it would be possible to charge at different locations, e.g. at home, work or shopping malls. In [58], the vehicle density at a shopping mall was estimated based on traffic volume data. However, it is not sure that the PEV would be charged after each trip and by considering type-of-trip data the impact of charging after certain trips can be investigated [60].

The charge power would affect the number of vehicles that could be charged simultaneously. A high charge power would reduce the number of PEVs that could be charged simultaneously [61]. On the other hand, since the charge time would be reduced, the coincidence of having a large share of PEVs charging simultaneously would be decreased.

In the following sections the impacts of PEVs on the power system in several different countries is presented.

2.2.2 Impacts of PEVs on national electrical power systems

Several studies have investigated the impacts of PEVs on a national level. In [10], the impacts of PEVs charging on the power system in Sweden was investigated for different scenarios, with the most severe scenario assuming that 80% of all vehicles in Sweden would be PEVs by 2030. This would result in an increased electricity consumption of about 6%, or about 9.5 TWh/year [10]. The total power used for charging depends on the individual charge power and the distribution of the charging in time. With one phase 230 V/10 A charging, the accumulative total power would reach a maximum of 3000 MW, which is about 10% of the installed power generation capacity in Sweden. Hence, there could be a need to increase the capacity on a national level or alternatively to coordinate charging to take place during off-peak hours [10].

A study from U.S.A. indicates that more than 70% of the vehicles in U.S.A could be converted to PEVs without exceeding the existing generation capacity if charging was conducted during off-peak hours [55]. However, the maximal possible PEV share varies between 18 - 127% among different states, in the case of controlled charging [55].

According to [56], the power capacity of the Portuguese power system may not be adequate if uncontrolled charging was conducted even for low penetration levels. The peak power would be increased by about 30% for a penetration level of 17%. However, the energy consumption would only be increased by about 3.2% for the same penetration level.

The installed power capacity in France would, according to [62], be about 124 GW in 2015. By charging PEVs in an uncontrolled manner, about 10% of the vehicle fleet could be supported by the power system. If the charging were coordinated, the capacity would be enough to supply more than 70% of the vehicle fleet with electricity [62].

The following statements can be found in most studies: firstly the increased energy demand is not the major problem since the energy needed is minor in comparison with total energy consumption in most countries; secondly, the generation and transmission capacities are the limiting factors when it comes to a massive introduction of PEVs. This could be solved by controlling the time when the charging should be conducted, either by legislation or by giving customers incentives to adjust the timing of the charging, i.e. DR.

From these studies it can be concluded that the impact on the power system would likely be more severe for countries with low electricity consumption per capita than for countries with higher consumption. For countries with low electricity consumption, the power system and generation capacity are designed for lower consumption and the added load from charging PEVs would be a larger share of the total load compared to countries with high consumption.

2.2.3 Impacts of PEVs on electrical distribution systems

In addition to the capacity limitations on a national level, the regional and local effects could be even more severe if uncontrolled charging was conducted. Most countries that have been investigated would have some limitations arising in their distribution systems in the event of a large scale introduction of PEVs.

The impact on a Spanish distribution system was investigated in [9]. The focus of the study was to estimate the reinforcement cost and losses in the distribution system for different scenarios. Two charge periods were examined, a night-time period with 85% of the vehicles connected and a day-time period with 40% of the vehicles connected. With 60% of the vehicles being PEVs, the investment cost could increase by up to 15% of the actual distribution system investment costs and the energy losses could increase by up to 40%.

A study of a distribution system in Germany indicates that a penetration level of 50% could be hosted within the existing distribution system if the charging were controlled [63]. Furthermore, the effects would be most severe in the low voltage distribution system.

A Portuguese distribution system analysed in [64] would experience problems with voltage drops at penetration levels below 10% if no controls were applied. Simulations were conducted in PSS/E and considered the average drive distance, i.e. the charge time would be calculated according to the electricity consumed/day instead of according to the size of the battery which also is important in order to obtain reliable results. However, instead of charging daily, charging was assumed to take place when the battery was empty.

The impact of PEVs on a distribution system in Canada was modelled using a stochastic approach in [58]. The study takes into consideration that the PEVs can be charged at different locations and that charge behaviours will vary between different areas. It is assumed that charging can be conducted at home, at work or at a retail location. The results show that for high penetration levels, there will be problems with capacity and transformer overloading. In the residential area, there might also be problems of voltage drops due to the long over-headlines.

In the studies mentioned here, many distribution systems would experience capacity problems if charging were uncontrolled. By controlling charging, the impact could be reduced and a larger PEV share could be incorporated. In the following section, different approaches for coordination or controlling charging are described.

2.2.4 Alternatives to reduce the impacts

Different approaches can be used to limit the impacts on the distribution system due to PEVs. A simple approach is to use a TOU tariff to give customers incentives to schedule their charging [64]. Although the demand could be shifted with this tariff, it is possible that the PEVs could cause new peak loads by using this type of tariff [54].

More advanced charge strategies could be to only allow charging if the capacity in the power system is sufficient [64], or to schedule charging in order to minimize the losses [8, 65]. In [8], an optimal charge profile for a residential distribution system was found by varying charge power and charge time. This was achieved by using quadratic and dynamic programming, whereby quadratic programming would be preferable due to shorter computational time and better accuracy. The optimal charge profile would reduce the losses simultaneously as the voltage profile was improved. Similarly, [65] optimized the charging by minimizing the losses. However, the results were compared with other optimization algorithms, i.e. maximizing load factors and minimizing load variance. When using these algorithms, losses stayed in the same range but computational time was improved.

The charging of PEVs, could also be scheduled to increase self-consumption of solar PV electricity [59]. However, due to the low coincident factor between solar PV production and the charging pattern of PEVs, the possible increase in self-consumption was limited for the Nordic region.

Even though it would be beneficial for the distribution system operator (DSO) if charging were conducted according to these smart charge algorithms, it requires PEV owners to allow the DSO (or an external party) to control the charging, i.e. some sort of DLC or that incentives are provided so PEV owners can schedule their charging accordingly.

Another way of dealing with the impact on the power system is to use the energy stored in the batteries to support the power system during situations of shortage. This concept is called vehicle-to-grid (V2G) and has been discussed over the last decade. The economic aspects of V2G are, among others, described in [66] and [67]. V2G will increase the cycling of the batteries and depending on how the V2G is controlled, the lifetime of the battery could be affected [67, 68]. According to [67], the cost associated with V2G was estimated to be about US$ 0.16 - 0.30/kWh, which would be high compared to base load electricity generation in many areas (in USA, about US$ 0.05/kWh) [67]. Instead the highest revenue is achieved if the PEV were to participate in the balance market, where not only the energy but also the power available is paid for [66]. The balance market varies for different countries and it is not always beneficial for the customer to participate [69]. Usually, the bid size on the balance market is high, which means that several vehicles must be aggregated to provide the power needed to participate in the market [70]. Experimental studies on V2G technology has been conducted in USA [71], and demonstrating projects are ongoing in e.g. California and Denmark [72, 73].

To reduce the cycling of the battery, unidirectional V2G can be applied [70]. An aggregator that controls a vehicle fleet could be regulating both up and down by increasing or decreasing the charging power. However, this adds limitations on the power the aggregator could provide. Different control algorithms were presented in [70] and the results showed that optimized algorithms offer benefits to all participants.

2.3 Thermal energy storage

Thermal energy storage (TES) can play a key role in a future energy system, not only by creating a buffer to arbitrage market prices, but also by promoting more efficient use of resources and variable small scale technology, such as micro-combined heat and power (μCHP) units, solar thermal and heat-pump (HP) [74–78]. In combination with μCHP, the TES could, for example be used to reduce utility peak demand and energy costs [79, 80].

The most common TES technology today is the sensible TES, using water as the storage medium [81, 82]. However, latent TES using phase changing materials provides several advantages over sensible TES, such as low losses and higher energy density [83]. Today, a large share of the research conducted in respect to TES focuses on phase changing materials and the cost of latent TES could be competitive with sensible TES, although there are concerns regarding long term degradation of the phase changing materials [84].

To determine the possible benefit of a TES, the modelling approach is important [76, 85]. Generally, a TES could be modelled based on the first or second law of thermodynamics, where the latter considers the exergy efficiency, i.e. that high temperature heat is more valuable than low temperature heat [85]. Another factor that would affect both the losses and the efficiency of the heating system is the level of stratification of the TES [76].

In addition to fluctuations in the heat demand and production, the optimal size of a TES would also depend on the size of the heat producing system [86, 87]. For systems producing both electricity and heat, the electricity tariff structure would also affect the optimal size of the TES [86].

Although TES investments could be beneficial in combination with several generating technologies such as solar thermal, HP or μCHP, it is possible that investment in other technologies would be more attractive compared to investments in TES. With a large variety of different technologies to invest in, it could be difficult to find the most beneficial investment option. One alternative to assist in the decision process is to formulate and solve this as an optimization problem [88–92]. Commonly, the problem is formulated as a mixed integer linear programming (MILP) or mixed integer nonlinear programming problem [89].

Investments in TES have been considered as a possible technology in several investment decision models such as [88, 89, 91]. In these models, the TES has been modelled as an energy deposit without considering any temperature changes in the storage, where the losses is estimated as a fixed percentage of the stored energy. With more detailed models based on the second law of thermodynamics, the efficiency and operation of the TES would be more accurately reflected. This would also affect the units connected to the TES [76, 93].

2.4 Research gaps

As presented in this chapter, DR, and especially RTP, has extensively been studied during the last decade. Most studies consider DR to be included in the price formulation on the electricity market, which could be of importance if a large number of customers participate in the DR program. However, as the RTP schemes are designed in Sweden, customers are directly charged with the day-ahead electricity price and the retailer needs to estimate how customers would schedule their loads. For small participation levels, the effects on the retailer would be limited, although the distribution system could be negatively affected locally. Hence it would be important to study to what extend the distribution system would be affected under such tariffs.

If issues are found, it is important to find solutions to these issues. Although D-LMP could be used to reflect local conditions, it may be difficult to implement such tariffs under the Swedish regulatory framework. Other solutions, such as power based network tariffs might be easier to implement and could also result in a load schedule that would be preferable from a distribution system perspective. However, how these tariffs would affect the customers' benefits and the distribution system in combination with an hourly electricity tariff has previously not been investigated.

Although PEVs have been studied intensively around the world, only a limited number of studies have been conducted under Swedish conditions. The majority of the studies focused on the transmission system level. On a local level the impact could be more severe, but would also vary within different areas. In addition, since PEVs could be considered as a flexible load, it is important to consider this load when investigating the potential for DR in distribution systems.

Studies have shown that, with increased share of RES, the volatility in the electricity price could be increased. This could result in increased incentives for customers that schedule their loads according to a RTP tariff. However, since scheduling in turn could affect the electricity prices, it is possible that there exists a synergy between DR and wind power. To the author's knowledge, this aspect has not previously been studied.

The possible benefits of using TES in combination with RES, such as solar thermal or μCHP units, have been verified in several publications. However, the majority of these studies consider either TES in combination with a single RES technology, e.g. solar thermal or μCHP, or they propose a simplified TES model. For investment decisions, several technologies must be compared simultaneously, and with a more detailed TES model more reliable results would be obtained. Although a model based on the second law of thermodynamics would be preferable from this perspective, it would not be possible to solve using a MILP model. Nevertheless, it could be possible to model the TES in greater detail compared to the current practise.

Chapter 3

Research approaches and model development

This chapter presents the research approaches and models developed in this thesis. The first section presents an overview of the research approaches and appended papers while the different parts and sub-models are briefly described in the subsequent sections. A more detailed presentation of the models and approaches can be found in the appended papers.

3.1 Overview of the research approach

The starting point of this project was to investigate the impact of PEVs on the local distribution system in Gothenburg and how to facilitate the PEVs more efficiently, e.g. by schedule the charging. From that point the work has evolved to include other flexible loads, such as electric space-heating and domestic hot water boilers (HWB). Furthermore, the possible benefits of DR were investigated for residential customers, distribution systems and wind power producers.

One of the main contributions from this work is the customer scheduling model, which can be used to schedule the flexible demand for residential customers. The model consists of two sub-models, the PEV scheduling model and the flexible load model, which considers loads such as electric space-heating, domestic HWB, dishwashers and laundry and drying machines. The space-heating scheduling part has also been integrated into a market model. Furthermore, a grid model has been developed to estimate the impact on distribution grids. Fig. 3.1 presents an overview of the developed models and which parts are included in the appended papers. As can be seen, **papers I-III**, consider only PEVs, **papers V and VII** consider only other flexible loads, while both PEVs and other flexible loads are considered in **papers IV and VI**. In **papers I-IV and VII** the loads were scheduled on an aggregated level, e.g. to reduce the grid losses, while in **papers V-VI** the loads were scheduled on an individual basis to assess the benefits on a customer level.

The models have been implemented in General Algebraic Modelling System (GAMS), a high-level modelling system for mathematical programming and optimization [94]. The customer scheduling model has been solved using the MILP

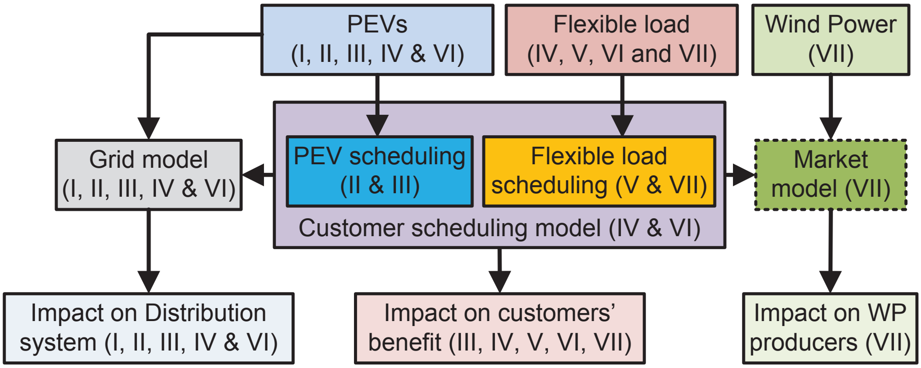


Figure 3.1: An overview of the proposed models and how this is linked to the appended papers.

solvers XA [95], while the grid model has been solved using the non-linear programming solver MINOS5 [96].

One possible way to increase the potential for DR could be to invest in TES. However, investing in TES is associated with additional cost, mainly due to the installation but also due to energy losses from the TES. In **paper VIII**, a TES model was proposed for investment and planning tools, such as the *distributed energy resources customer adoption model* (DER-CAM). The TES model was implemented and integrated in DER-CAM and used in a case study of commercial buildings in California. Although DER-CAM could be used for residential customers, the focus has traditionally been on commercial and industrial buildings.

3.2 Modelling of electrical distribution systems

One part of this thesis has been on the impact of DR and PEVs on distribution systems. In **paper I** the impact of PEV charging in distribution systems was modelled within the commercially available software Power World [97]. To enable the possibility of scheduling the PEVs charging to reduce the active power losses, an AC optimal power flow model was developed and implemented in GAMS (in **papers II-IV and VI**), based on the optimal power flow framework described in e.g. [98].

3.2.1 Feeder reconfiguration

Distribution systems could be designed in different ways. One common design in Sweden is the open loop radial distribution system. This system design could allow the system operator to quickly restore the electricity supply to the customers after a failure by changing the status of the tie and sectionalizing switches. However, this is only possible if the remaining feeders could handle the additional load from the disconnected feeder. In **paper III**, an analytical approach was developed to identify the reconfiguration option with the highest power capacity. The capacity would depend on how the demand is distributed among the secondary

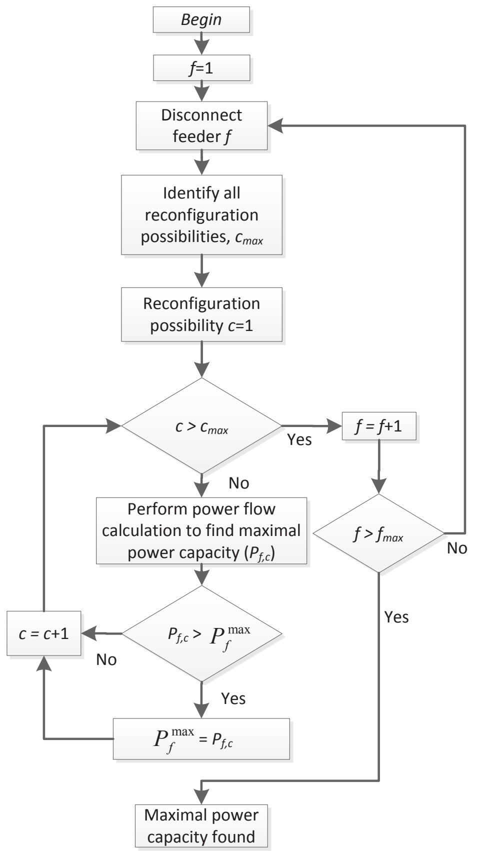


Figure 3.2: Flowchart of the approach developed in **paper III** to identify the reconfiguration possibility that results in the highest power capacity.

substations. In **paper III**, the demand was assumed to be distributed according to the peak demand of each substation. Fig. 3.2 presents a flowchart of the developed approach.

3.3 Modelling of PEVs

The number of PEVs that could be handled by a distribution system depends on the available capacity in the distribution system, the existing load and the charge power. However, this must be put into the context of how many vehicles that are located within the distribution system. Furthermore, since the main purpose of a PEV is to transport persons from one location to another, the PEV will not be situated at the same location during the entire day. With a charge infrastructure in place it could be possible to charge at different locations throughout the day.

In **paper I**, a deterministic approach was used to investigate the worst case scenario, i.e. PEVs charging at the peak hour of the year in two different distribution systems, a commercial and a residential. Demographical data was used to

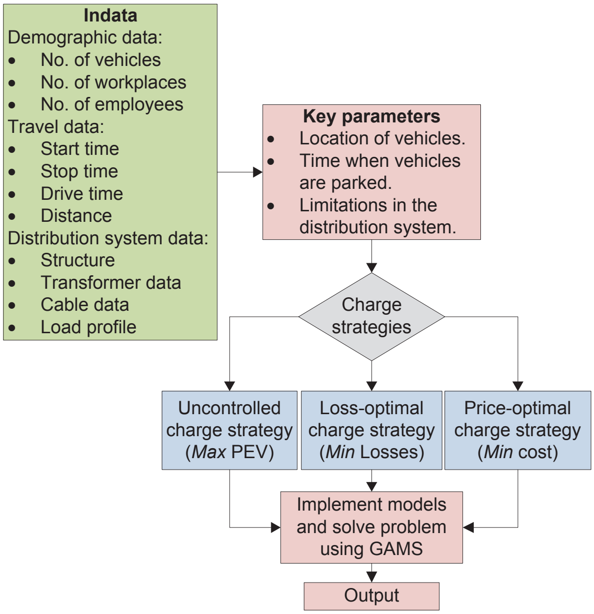


Figure 3.3: Flowchart of the approach used for the PEV scheduling model.

estimate the number of vehicles within each area during the day-time and during the night-time in order to assess the severity of the impact on the distribution systems. However, it is unlikely that all PEVs are being charged at the same time. To make more realistic scenarios, it is important to know how the PEVs are actually being used. This may, however, be difficult since only a limited number of PEVs are available today. In **papers II-III** a PEV scheduling model was developed to assess the possible impact of PEVs on the distribution system, including vehicle usage statistics. Although it is uncertain if PEVs will be used in the same way as conventional vehicles, it is probably a realistic assumption. This is especially true for plug-in hybrid electric vehicles since they do not suffer from range limitations while the usage pattern for battery electric vehicles might alter. With improvements in battery technology and investments in fast charging stations, the range limitation may be less of a concern and using statistical data from conventional vehicles could be a valid assumption.

Fig. 3.3 presents a flow chart of the proposed approach used in **papers II-III**. As can be seen, three different charge strategies are investigated, i.e. uncontrolled, loss-optimal and price-optimal charging. To assess these strategies, three key parameters are needed: the location of the PEVs (i.e. where they can be charged); the time when they are parked (i.e. when they can be charged); and technical data of the distribution system. Some of this information is usually available for the DSO, such as data for the distribution system, number of connections and customer types. However, the DSO usually does not know how many vehicles there are within an area, or how these vehicles are used. As stated above, demographical data and vehicle usage statistics could be used for this.

In the uncontrolled charging strategy, charging was assumed to be conducted immediately after the last journey while charging was scheduled to reduce active power losses in the loss-optimal strategy and to reduce the charging cost in the price-optimal strategy, as long as the PEVs were fully charged before their next journey.

A large share of the journeys is work related, e.g. commuting journeys to/from work. Some of these journeys are conducted by other means than by a car, e.g. by bike or public transportation. It was assumed that the vehicle commuting share, i.e. the share of the journeys conducted by a car, would vary between different areas depending on the number of cars per person in an area, i.e. an area with high numbers of cars per person would probably use the car for commuting purpose more often compared with areas with low number of cars per person. While this is valid for persons commuting from an area, it is unlikely that everybody that commutes to the area comes from the same location, hence the average vehicle commuting share has been assumed for commuting journeys to an area. While only commuting journeys were considered in **paper II**, other journeys, such as shopping and leisure related journeys, were considered in **paper III**.

3.4 Modelling of flexible loads

For many loads, the level of flexibility would be a trade-off between the possible savings and the inconvenience for the users. Loads with low impact on comfort, such as space-heating, may not demand such high savings compared with loads with high impact on comfort, such as cooking or lighting. As for PEVs, different approaches could be used to model the flexible loads. In **papers IV and VII** the flexible loads were scheduled on an aggregated level while in **papers V-VI** the flexible loads are modelled individually to assess difference between different loads. A flowchart of the approach developed in **papers V-VI** is presented in Fig. 3.4. As can be seen, the customers are first scheduled on an individual basis and then aggregated together to assess the effects on the distribution system.

The loads considered flexible in this thesis include electric space-heating, domestic HWB , dishwashers and laundry and drying machines. This section presents the developed customer scheduling model and the approaches used to estimate the potential benefits for customers and DSOs by scheduling these flexible loads.

3.4.1 Residential space-heating

Residential space-heating is one of the major residential electricity loads in Sweden. About 10% of the total electricity consumption was used for space-heating in detached houses in 2012 [100]. About 29% of the houses were heated by electric space-heating only, including air-to-air HP and air-to-water HP. In addition, 17% of the houses were using other kinds of HP, e.g. ground source HP, and 21% of the houses were using biofuels in combination with electric space-heating [100].

Traditionally, the heat demand is controlled based on the outdoor temperature, but due to the thermal inertia of the building, part of the heat is stored in the building [101]. For customers who accept certain temperature variation indoors, this stored heat could be used to shift the energy usage in time. In addition to

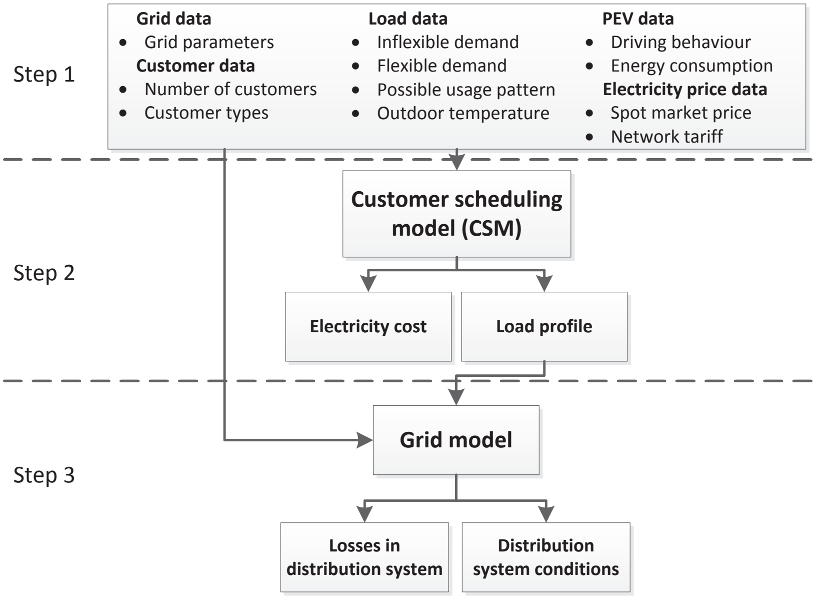


Figure 3.4: Flowchart of the approach used for the customer scheduling model.

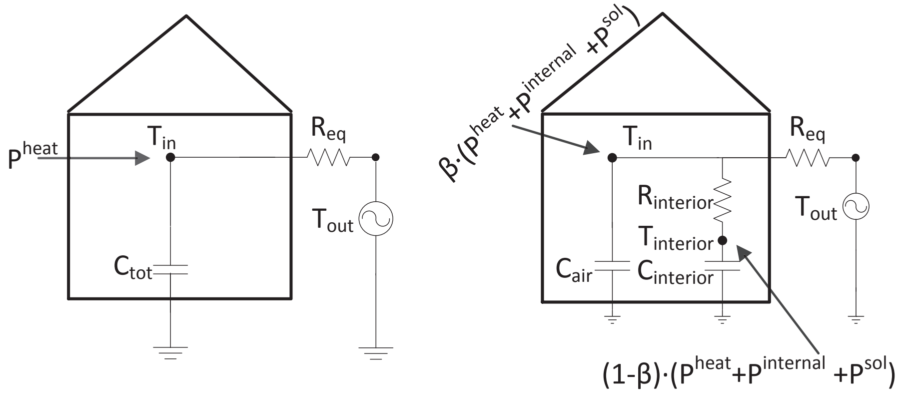
the thermal inertia, the possibility to shift the heat demand depends on the type of heat system. An air-to-air HP supplies its heat directly to the indoor air, while a hydronic floor heating system would heat up the floor before the air is heated.

As described earlier in Section 2.1.1, the heat system in a building can be modelled as a lumped capacity model. As shown in Fig. 2.2, the temperature would vary for different parts of the building, and by considering several nodes the accuracy of the model increases. In **papers IV-V**, a simplified thermal model of the building based on a first order system was proposed as shown in Fig. 3.5a. The disadvantage with this simplified model is that no difference between the indoor and the interior or wall temperatures were considered which could lead to possible overestimates of the flexibility in the heat system. To increase accuracy, the space heating model was further developed in **paper VI** to consider both the temperature of the interior and the air temperature, as shown in Fig. 3.5b. Moreover, since a large share of the detached houses are using HP [100], a simplified model of a HP was proposed in **paper VI**.

By controlling the heat system, it could be possible to reduce the energy demand for heating and obtain a better indoor climate [101]. However, since the main purpose of this thesis has been on assessing the benefit from DR, energy conservation has not been considered in the model, although it could have been implemented.

3.4.2 Other flexible loads

Although a large share of the electricity used in detached houses in Sweden is used for space-heating purposes, other loads could be considered as flexible. In detached houses in Sweden, domestic hot water is commonly produced by an



(a) One temperature node.

(b) Two temperature nodes.

Figure 3.5: A schematic circuit diagram of the thermal models of a building used in **papers IV-VI**, considering one (a) and two (b) temperature nodes within the building. R_{eq} represents the equivalent resistance of the building.

electric HWB. Traditionally, the HWB is coupled with a storage tank which is thermostatically controlled, meaning that as soon as the temperature drops below a certain level, the electric heater starts heating the water again. This may not always be needed and the heating could be shifted in time. The simplified HWB model proposed in **paper VI** estimates the temperature of the tank based on the input and output energy, where the heat losses are included in the energy output. By shifting the energy input in time, the temperature of the storage would vary, hence the heat losses would also vary. However, as for the space-heating model, energy conservation has not been considered in the case study and the losses have been assumed to remain, although the temperature of the hot water tank would vary by scheduling the HWB.

Other loads that have been considered flexible include dishwashers, laundry machines and clothes dryers. When assessing the potential benefit for customers or distribution systems from shifting these loads in time, it is important to know how these loads would have been used if no load shifting were conducted, i.e. a reference case. In this thesis historical load data from a measurement campaign have been used as a reference case. This also sets the possibilities for shifting the demand in time, e.g. if no appliances would have been used in the reference case, there is no load to shift in the case with DR. Possibilities of shifting the demand would also have certain constraints on how they could be shifted, e.g. the clothes dryer must start after the laundry machine.

3.5 Market modelling

The electricity bill consists of an electricity cost and a distribution or network cost. Since 2012, it has been possible for residential customers in Sweden to sign up for hourly electricity prices based on the day-ahead market [48]. In **papers III-VI**, these hourly prices have been used as the price signals for price-responsive

Figure 3.6: A map over the Nordic power market Elspot, indicating the geographical location of the different price-areas [11].

customers to schedule their loads. Although some DSOs have started to charge their customers with a power based network tariff [102], the network cost was based on the traditional energy based network tariff, where the customers are charged with a fixed price per kWh electricity used.

In **paper VI**, the impact of different network tariffs was investigated. An energy based network tariff was compared with two different power based network tariffs, either based on the monthly peak demand or the daily peak demand.

As has been discussed earlier in Section 2.1, DR may affect the electricity prices, since the price of electricity both depends on the generation and consumption of electricity. However, with a limited number of responsive customers, the impact on the day-ahead spot price would be minor [23]. Although the number of price-responsive customers would be limited on a national level, it could be high locally, thus affecting the local distribution system. Furthermore, as the hourly electricity pricing tariffs are designed in Sweden today, residential end-use customers do not participate directly in the market but know the electricity prices in advance. Due to these reasons, the possible influences of DR on the electricity market were not considered in **papers III-VI**.

With the increasing amount of wind power in the power system the volatility in the electricity price could increase. This could affect the incentives for customers to schedule their loads. However, by shifting the demand to the low price period,

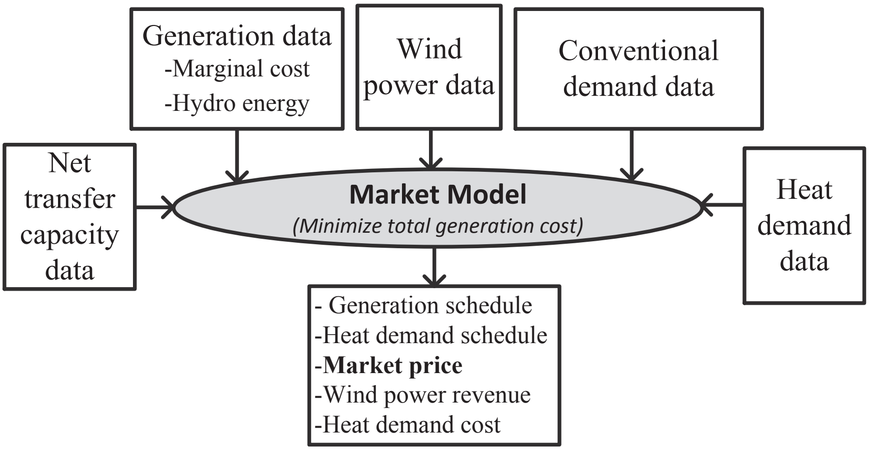


Figure 3.7: The proposed framework of the market model with flexible demand scheduling.

the volatility of the electricity price could be reduced [103], which in turn could affect the revenue for the wind power producers. To assess the potential benefit of DR on wind power producers and vice versa, the space-heating module of the customer scheduling model was, in **paper VII**, integrated into a market model of the Nordic day-ahead market Elspot. The market model was developed and proposed in [104] and includes the four Nordic countries Sweden, Norway, Finland and Denmark. The countries are divided into several price areas as shown in Fig. 3.6.

Fig. 3.7 presents the framework of the market model. As can be seen the objective is to minimize the total system generation cost. This is achieved by scheduling both the flexible demand and the generation. The power flow between the price-areas is limited by the net transfer capacity. By including the customers' flexibility in the market formulation, it could affect the electricity price and hence the revenue for the wind power producers.

The location and amount of wind power would affect the possible influences of the market price. The wind turbines were distributed based on the estimated annual revenue, which depends on both the wind availability and on the area-prices. The wind availability data and wind speed conversion to electric power was based on the approach described in [105].

3.6 TES modelling in DER-CAM

As previously discussed in Section 2.3, energy storages could be used to increase the DR potential and lower the energy cost for customers. One part of this thesis, i.e. **paper VIII**, addresses the modelling of TES for the investment decision tool, DER-CAM. This section presents a short description of DER-CAM and of the developed TES model within DER-CAM.

3.6.1 DER-CAM

DER-CAM is a MILP program written in GAMS with the objective to minimize the annual costs or CO_2 emissions for providing energy services to a site or building by investing and dispatching distributed energy resources. The possible resources to invest in include: on-site electricity generation, e.g. fuel cells, μCHP and solar PV; storage technologies, e.g. batteries and cold/heat storage; PEVs and cold/heat providing technologies, such as HPs and absorption chillers.

The key inputs are customer loads, electricity and natural gas tariffs, and data of available technologies. Key outputs include annual energy costs and CO_2 emissions, the optimal on-site capacities and dispatch of selected technologies. DER-CAM considers the interdependence of results. For instance, building cooling technologies will reflect the benefit of electricity demand displacement from possible heat-activated cooling, which can lower building peak loads and, therefore, the on-site generation or utility purchase requirement. Reduced on-peak usage also has a disproportionate benefit on bills because of power tariffs and time-of-use (TOU) energy rates. A more detailed description of DER-CAM can be found in **paper VIII**.

3.6.2 TES model for investment decisions

To accurately model the TES, aspects such as stratification would be important since the efficiency of both heat loads and heat generating units would be affected by the actual temperature of the TES [76]. This has however not been directly considered in the TES model. The reason for this is to avoid endogenous problem formulations, which cannot be solved in a MILP model. Although stratification is not directly modelled, the energy losses could be modelled to match either a stratified TES or a fully mixed TES, i.e. a TES with uniformed temperature profile. In addition, the model incorporates the possibility of using the TES with both high temperature and low temperature heat sources. A schematic figure of the proposed TES model is presented in Fig. 3.8. As can be seen, to allow the TES to be charged by both high temperature heat sources and low temperature heat sources, the TES is modelled with two temperature sections. Furthermore, the losses are calculated based on the energy stored in the TES and on a static part, based on the unusable heat in the TES.

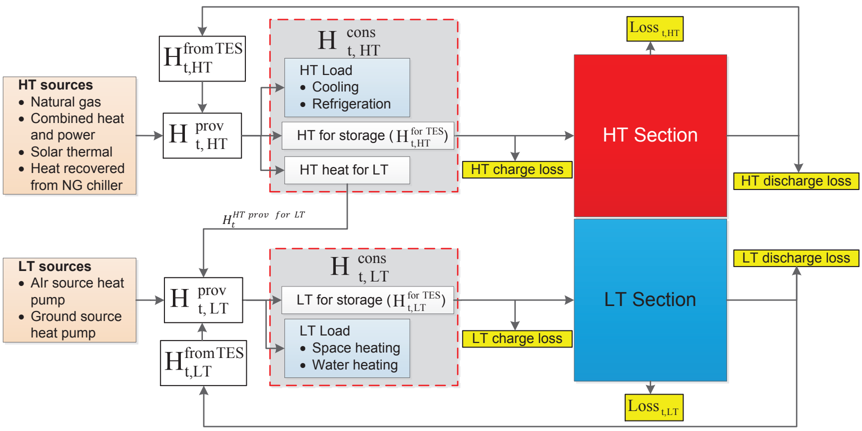


Figure 3.8: Schematic figure of the thermal energy storage with a high temperature (HT) and a low temperature (LT) section.

Chapter 4

Results and discussions

This chapter summarizes the main results from this thesis work. In the first section, the effects of PEVs and DR on distribution systems are presented followed by the influences of different network tariffs. In the third section, the possible benefits of DR in power systems with high wind power shares are presented. Finally, the key findings from the TES study are presented.

Generally, only the main results are presented. However, due to space restrictions for the papers, this chapter provides a more comprehensive discussion of the results and in some cases also additional results. The results are discussed and analysed from both the customers' perspective and the distribution system's perspective.

4.1 Effects of PEVs and DR on distribution systems

This section presents the main findings from **papers I-IV**. The focus has been on the day with highest demand, i.e. the peak day. The studies include overloading of the distribution system due to DR and PEVs, as well as active power losses and possible cost reduction achieved by price-responsive customers who schedule their loads.

4.1.1 Effects of scheduling PEVs

In **paper I**, the maximum number of PEVs that could be charged in a commercial and a residential distribution system without violating operating constraints during the peak hour was estimated. The results indicated that, in the investigated areas, the 400 V grid could withstand a full roll-out of PEVs with merely one overloaded cable, even at the peak hour. The 10 kV system would, on the other hand, experience both transformer and cable overloading. In the residential area, one of the transformers was overloaded even without any PEVs. With this transformer replaced, the maximum share of PEVs that could be accommodated was 56% and 64% for the commercial and residential area respectively.

By considering vehicle usage statistics, more realistic charging scenarios could be obtained. In **paper II**, two different charging strategies, i.e. uncontrolled charging and loss-optimal charging, were developed based on vehicle usage statistics. In **paper III** a third strategy based on the charging cost, i.e. price-optimal charging, was proposed. In addition to commuting journeys, other journeys were also considered in **paper III**.

Papers II-III includes the 10 kV distribution system investigated in **paper I** but was extended to include additional feeders. On the other hand, the impact on the 400 V grid was not considered in these papers. In the following subsection the effects on load profiles are presented for the different charging strategies.

4.1.1.1 Effects on load profiles considering PEV charging strategies

Fig. 4.1 presents the load profile for the peak day in a residential 10 kV distribution system, when all vehicles are replaced with PEVs. The charging is either conducted only at home or both at home and at work. As can be seen, charging occurs during the peak demand period for the uncontrolled charging strategy. However, since vehicle usage statistics are used, the charging is distributed over a number of hours and the impact is less severe compared to the case presented in **paper I**.

It must be noted that, in **paper III** the maximum capacity of the distribution system was calculated using other values for transformers capacities, compared with the actual capacities within the investigated distribution system. The maximum capacity would be about 25% below the numbers presented in **paper III**, as shown in Fig. 4.1. Hence, the residential distribution system would be overloaded for the peak day even if no PEVs would be charging, in accordance with **papers I-II**.

If only uncontrolled home charging would be available, some PEVs would charge during the peak demand hours, resulting in an increased overload. With the price-optimal strategy, all PEVs are charged simultaneously and, although charging would be conducted during the night-time, the charging causes the demand to increase above the evening peak if more than 24% of the vehicles was replaced by PEVs. With loss-optimal strategy, charging is shifted away from the peak demand hours and all PEVs could be charged without affecting the peak demand.

By replacing three of the transformers with highest loading level, or by allowing a short term transformer loading level of about 130%, the maximum PEV penetration level increases to 49% for the price-optimal strategy, while up to 76% of the vehicles could be PEVs the charging would be uncontrolled. If charging at work would be available, all vehicles could be replaced by PEVs with the uncontrolled strategy, while the level remains at 49% for the price-optimal strategy. Although transformer overloading is not desirable, a transformer could be temporary overloaded with limited impact on the lifetime of the transformer [106], especially during the winter period due to the low ambient temperature.

The commercial area could handle a full penetration without exceeding the maximum capacity under all charging strategies, as can be seen in Fig. 4.2. However, for the simulated day, the charging would be shifted to hours with high demand within the area for the price-optimal strategy, indicating that the market price does not reflect the local conditions within this area.

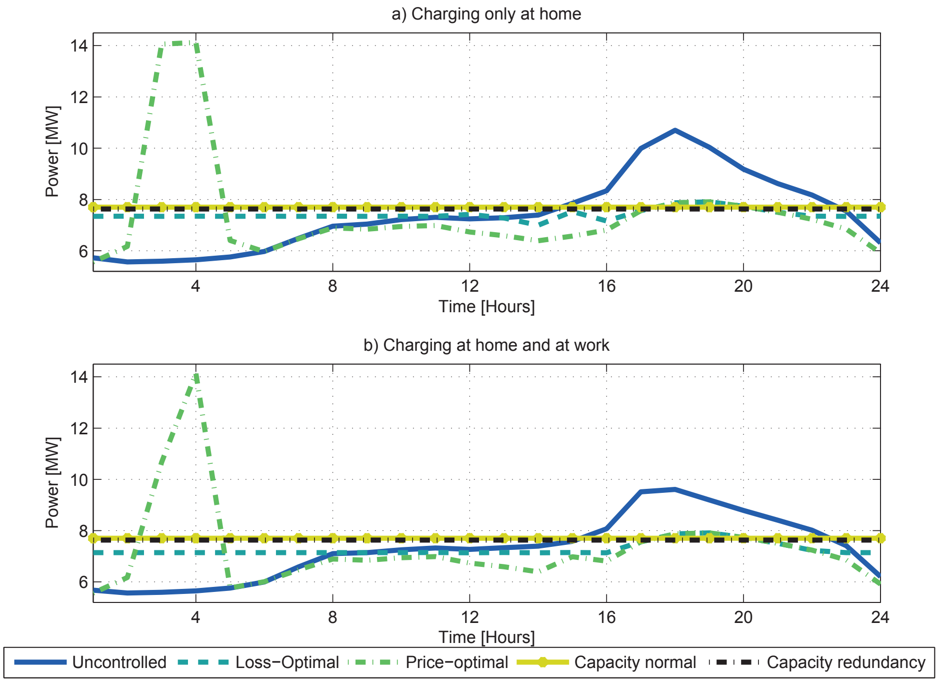


Figure 4.1: Load profiles in the residential area for the simulated day with all vehicles being PEVs: charging only at home (a) or charging at home and at work (b).

4.1.1.2 Effects on the active power losses

Comparing the different charging strategies, the active power losses in the residential distribution system would be increased by between 18-33% for the case with 100% PEVs as compared to the case without any PEVs. By applying the loss-optimal charging strategy, losses were found to be about 4% lower than the losses for the uncontrolled strategy, while losses would be increased by 4% for the case with the price-optimal charging strategy. For the commercial area, the increased losses were found to be between 2% to 6%, for the different charge strategies, i.e. considerably lower compared to the residential area. This is mainly due to the low number of PEVs charging in the commercial area. In contrast with the residential area, the losses were reduced for the price-optimal charge strategy for the case when only home charging was considered. The reason for this is due to the low number of PEVs available during the night and although the charging is scheduled to the same hours the increased demand during these hours is low compared to the demand during the hours when the charging would be conducted if it was uncontrolled. This indicates that for areas with a low number of PEVs, price-optimal charging could be beneficial from a distribution system perspective.

It is important to note that the losses presented here are only for one day, i.e. the day with highest demand. For days with lower demand, PEV charging would represent a larger share of the total demand. Hence charging could contribute to a larger share of the total losses.

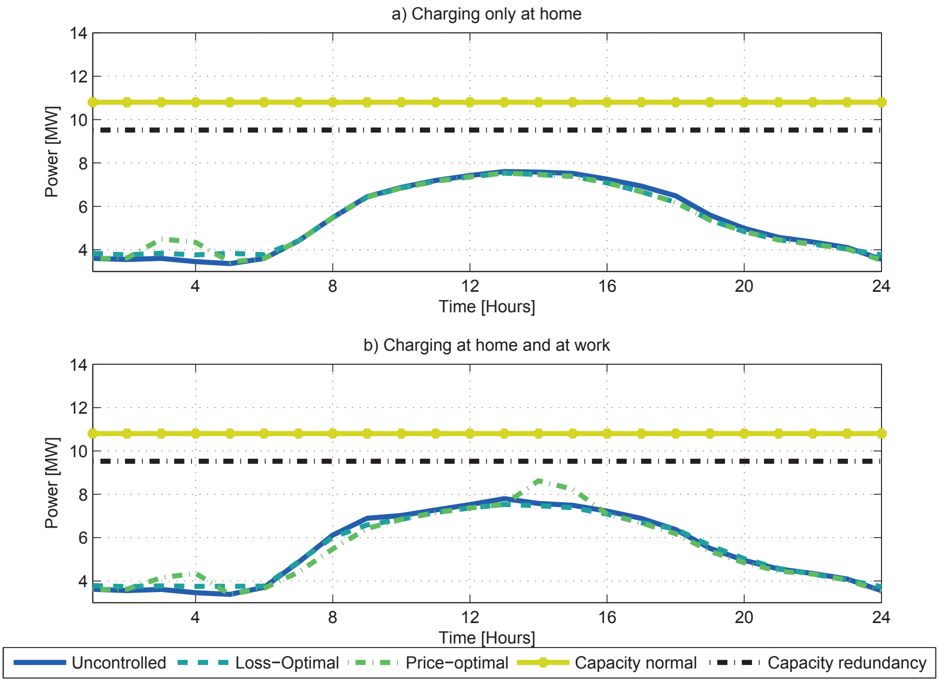


Figure 4.2: Load profiles in the commercial area for the simulated day with all vehicles being PEVs: charging only at home (a) or charging at home and at work (b).

4.1.1.3 Effects on charging costs

The charging costs would, as expected, be reduced for the price-optimal charging strategy. Compared with the uncontrolled strategy, the charging cost could be reduced by 15% in the residential area and between 11% and 16% in the commercial area. However, even for the loss-optimal control strategy, the cost was found to be reduced; by about 11% for the residential area, and by between 4% to 16% for the commercial area. Although the cost reduction was substantial in relative terms, in absolute monetary terms it was limited, about €0.1 per charge occasion. Additionally, because the electricity price varies every day, the cost reduction may differ for other days. Furthermore, the cost reduction is presented as the average cost per charge and individual savings would vary for the different PEVs, depending on the actual usage of the vehicles.

4.1.2 Effects of scheduling flexible loads on residential distribution system

In **paper IV**, the effects of scheduling the electricity used for space-heating were investigated for the peak day in 2008, under the different load scheduling strategies presented in **papers II-III**. The resulting load profiles are presented in Fig. 4.3. As can be seen, by scheduling the electric space-heating according to the loss-optimal strategy, the peak demand could be reduced in the distribution system,

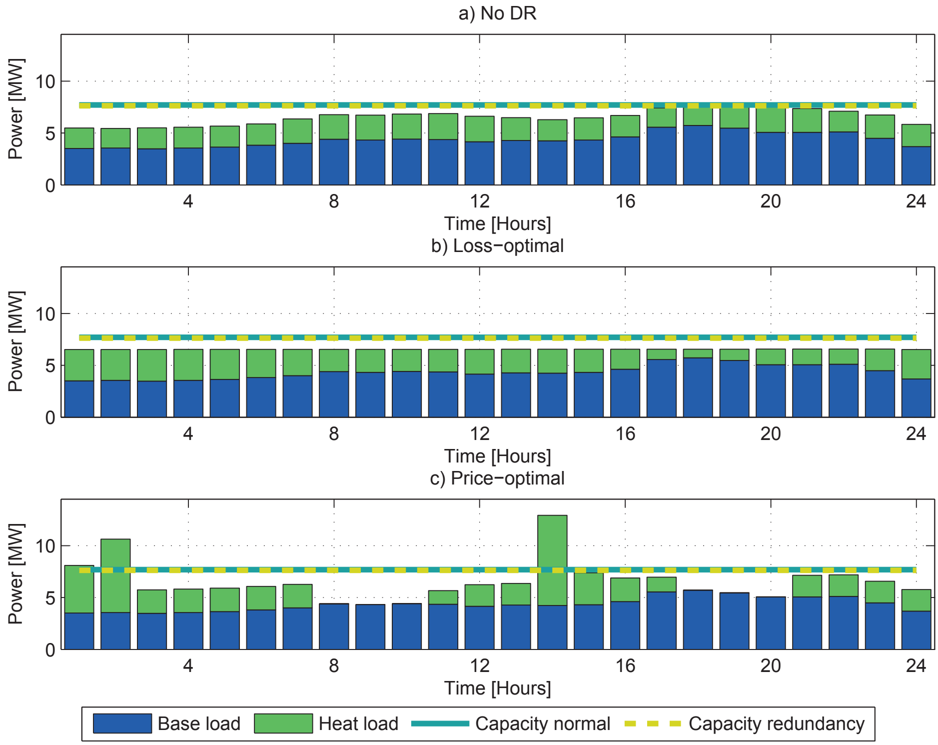


Figure 4.3: Load profiles in the residential area for the simulated day with the space-heating scheduled according to the different scheduling strategies.

whereas the peak demand could be increased under the price-optimal strategy. Similarly, the losses were found to be increased for the price-optimal strategy while they were reduced for the loss-optimal strategy.

4.1.2.1 Effects on electricity costs

By scheduling the space-heating according to the price-optimal strategy the possible cost reduction was found to be limited. The electricity cost could be reduced by about 2% for the simulated day, as compared to the case without scheduling of the space-heating. However, as for the case with PEVs, possible savings would only reflect this specific day. Hence the possible cost reduction could be increased for other days. In **paper V**, the load scheduling was performed for three different customers over a period of one year. In addition to space-heating, this study included scheduling of dishwashers, laundry machines and clothes dryers. Although the simulation included additional loads, the possible cost reduction was found to be low, by about 1.7% of the annual cost. One reason why the cost reduction was found to be lower in **paper V** could be that different years were simulated.

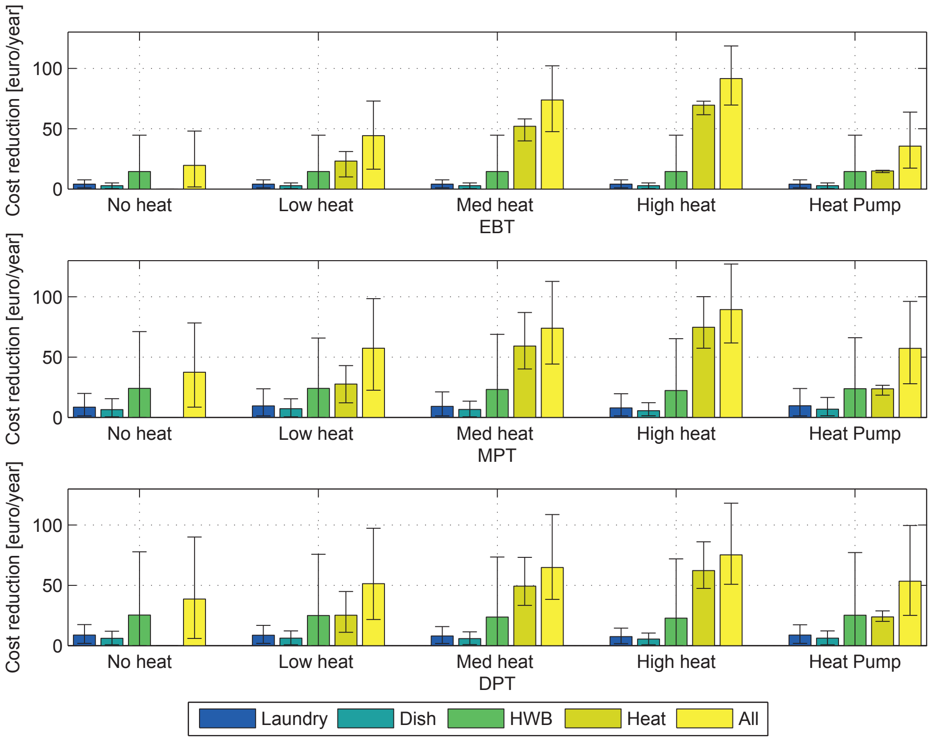


Figure 4.4: Average (bars) and individual (error bars) cost reduction for customers scheduling different loads compared with non-responsive customers, for the investigated network tariffs.

4.2 Effects of power based network tariffs

As discussed in Section 4.1.2, the customers' benefits from scheduling their demand according to the day-ahead electricity price would be limited, even for customers with high flexibility. At the same time, the tariff imposes a risk of increased peak demand locally in the distribution system. From a DSO's perspective, it would be beneficial if the customer scheduled the load according to the loss-optimal strategy. This behaviour could be promoted by replacing the traditional energy based network tariff (EBT) with a tariff by which customers are charged based on their peak demand, i.e. a power based network tariff (PBT).

In **paper VI** the customer scheduling model was used to investigate what impact alternative network tariffs could have on both customers' benefit and on the distribution system. The electricity prices were still assumed to be based on the day-ahead spot market while the network tariffs investigated include the traditional EBT and two different types of PBT, either based on the monthly peak demand (MPT) or on the daily peak demand (DPT). In the following sections, the main results are presented from both the customers' perspective and the DSO's perspective.

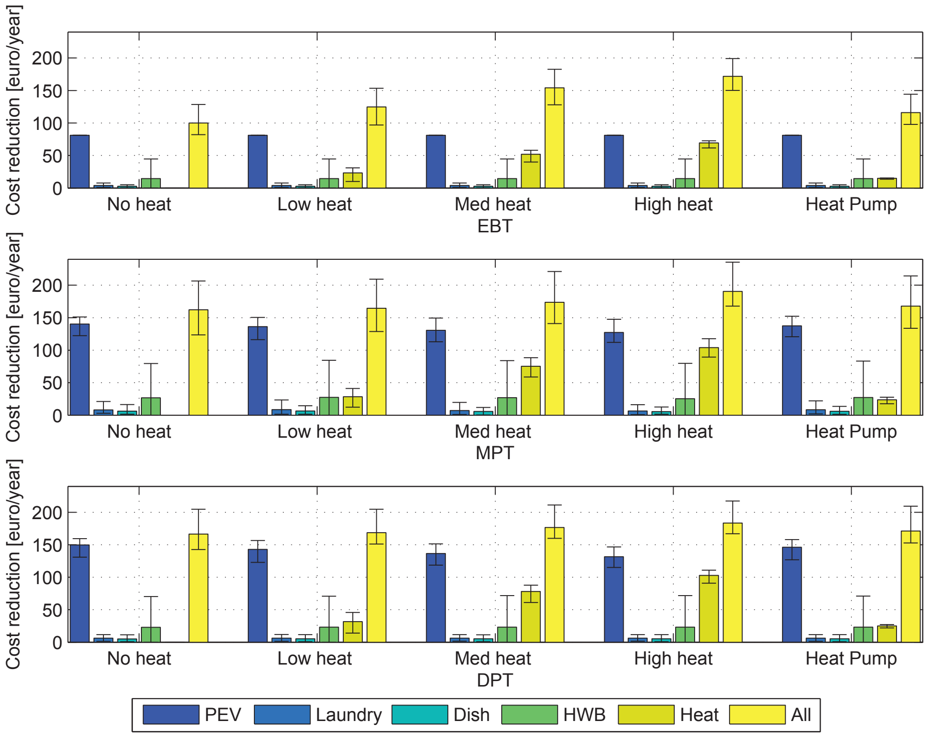


Figure 4.5: Average (bars) and individual (error bars) cost reduction for customers with a PEV that schedules different loads compared with non-responsive customers, for the investigated network tariffs.

4.2.1 Benefits' for the customers

Fig. 4.4 presents the average and individual cost reductions achieved by 20 different price-responsive customers, each simulated with five different thermal properties of their buildings. The electricity prices were based on historical day-ahead electricity prices from 2008. Simulations were conducted with different level of flexibility, i.e. scheduling the flexible loads one by one or scheduling all flexible loads together. As can be seen, electric space-heating contributes most to the cost reduction although HWB could contribute to a significant cost reduction for some customers. The reason for the large difference in cost reduction for the HWB is due to that some customer does not use electricity for domestic hot water while others have a high consumption. The possible savings for customers who only schedule dishwashers or laundry and drying machines would be limited in monetary terms, up to €23/year, although the possible gain increases with PBT, especially the DPT. In relative terms, the cost reduction was found to be between 0.2% and 4.4% under the EBT compared with 0.8-9.3% for the case with MPT, and 0.9-9.6% for the DPT, if all flexible loads were scheduled.

From a customer perspective, the introduction of PBT would be mostly beneficial for customers with a low load factor, i.e. for customers with large peak demand compared to the average demand. For customers with higher load factor

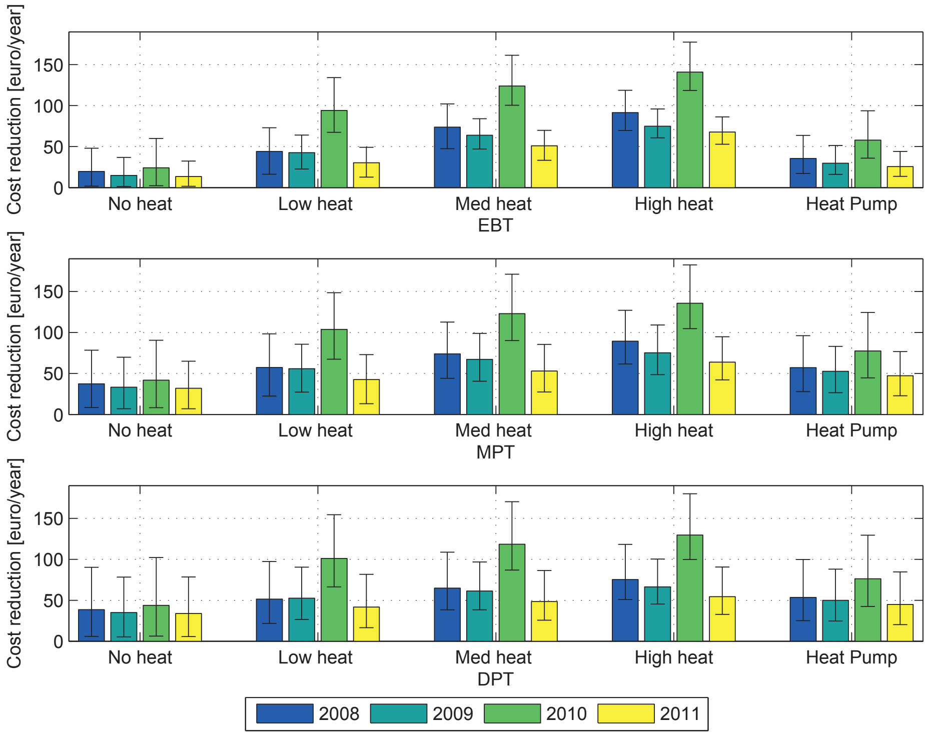


Figure 4.6: Average (bars) and individual (error bars) cost reduction for years 2008-2011, for customers without PEVs, scheduling all flexible loads.

the difference between the tariffs are reduced. The reason for this would be that customers with large variations in the demand could reduce their peak demand more than customers with small variations in their load profile and thereby affect the electricity cost more under a PBT.

For customers having a PEV, the possible cost reduction would be substantially increased if a PBT was introduced, as compared to the case with EBT, as shown in Fig. 4.5. The reason for this is due to the assumption that PEVs are charged immediately when they are parked, i.e. during hours with high electricity consumptions. By shifting the charging time, peak demand could be decreased considerably, resulting in high savings for the case with PBT. By scheduling all flexible loads, including PEVs, the electricity cost could be reduced by 3.3-8.2% under the EBT, 3.8-13.2% under the MPT and 3.8-13.2% under the DPT.

When investigating the customers benefits', the customers were assumed to utilize the PEVs in the same way every day, except weekends/weekdays. In reality PEV usage varies among the customers and for the different days. Hence the actual cost reduction would differ among the customers depending on their actual usage.

Fig. 4.6 presents the average and individual cost reduction achieved by the investigated customers for 4 different years, i.e. 2008-2011. As can be seen, the possible savings vary for every year. The highest savings could be achieved in 2010 due to the high price volatility in that year. The difference between the years could be more than double. Furthermore, it can be observed that the cost reduction varies most for the EBT compared to the MPT or DPT. One reason for this could be that, under the EBT, the only influencing factor would be the hourly electricity price, which would vary for the different years.

Although the cost reduction may be limited for some customers, the possible cost reduction could be increased with a more volatile market price. As discussed in Section 2.1, in a future with high shares of RES, the prices on the day-ahead market could become more volatile and the possible cost reduction could be increased, resulting in a higher interest for DR.

4.2.2 Effects on the distribution system

As discussed in Section 4.1.2, the possible impact of responsive customers on the distribution system could be increased if the day-ahead spot prices are used as incentives for customers to schedule their demand. These studies, e.g. **papers III-V**, consider that all customers would be responsive. In **paper VI** simulations with different shares of responsive customers, and penetration levels of PEVs were conducted to find the level when price-responsive customers could result in increased challenges for the distribution system. Furthermore, the possible gain that could be achieved by using a PBT compared to the EBT was investigated.

4.2.2.1 Effects on the peak demand and load profiles

Fig. 4.7 presents the load profile of the 400 V grid for two winter week-days for the case with two levels of responsive customers, i.e. 25% and 100%, and for the different network tariffs. As can be seen, with a low number of responsive customers the impact on the load profile is limited although the demand is generally shifted to the night-time due to the lower spot market prices during these hours. If all customers would be responsive the demand during the night-time would increase substantially, causing a new peak demand within the distribution system. Fig. 4.8 presents the change in peak demand in the 400 V grid, for the different tariffs and shares of responsive customers and PEVs. In the case without responsive customers, the annual peak demand in the 400 V grid was found to be 285 kW if no PEVs were available and 324 kW, if 50% of the cars would be PEVs. From Fig. 4.8, the following points can be noted:

- **With EBT**, the peak demand could be increased by more than 60% if all customers were responsive and no PEVs available. With 50% of the customers responsive the peak demand could increase by almost 20%. With 50% PEVs, the peak demand would increase further in relation to the case without responsive customers, if more than 25% of the customers would be responsive.

- **With MPT**, the peak demand could be decreased if up to 50% of the customers were responsive. If all customers were responsive, the peak demand could increase by up to 20% due to the increased coincident factor. In relation to the case without responsive customers, the possible benefits are increased if 50% of the vehicles was PEVs and up to 50% of the customers was responsive.

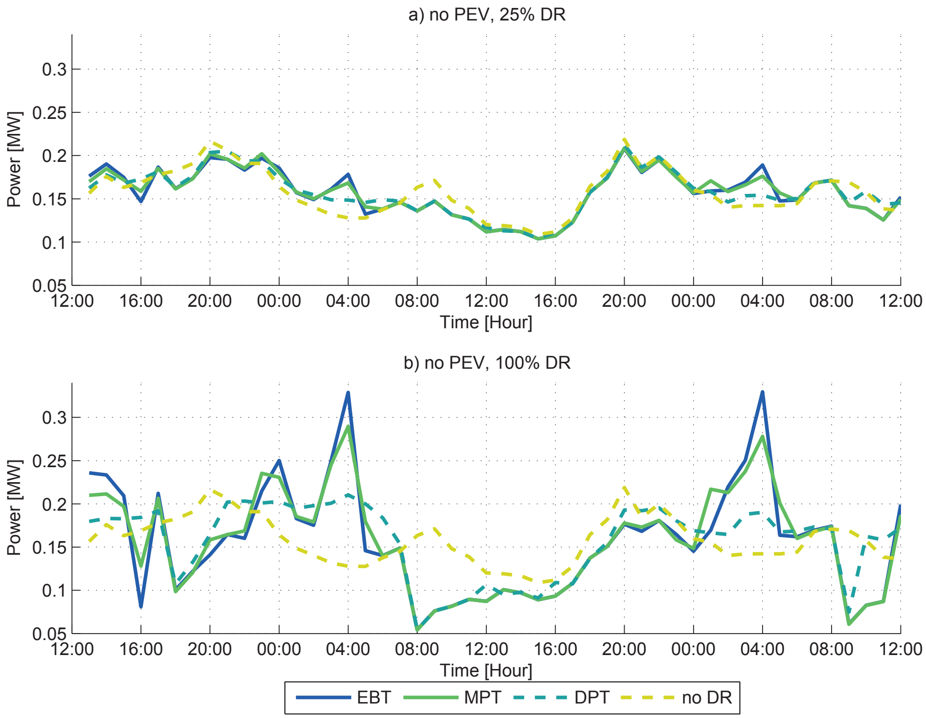


Figure 4.7: Load profiles for two winter week-days with 25% (a) and 100% (b) of the customers being responsive, without any PEVs.

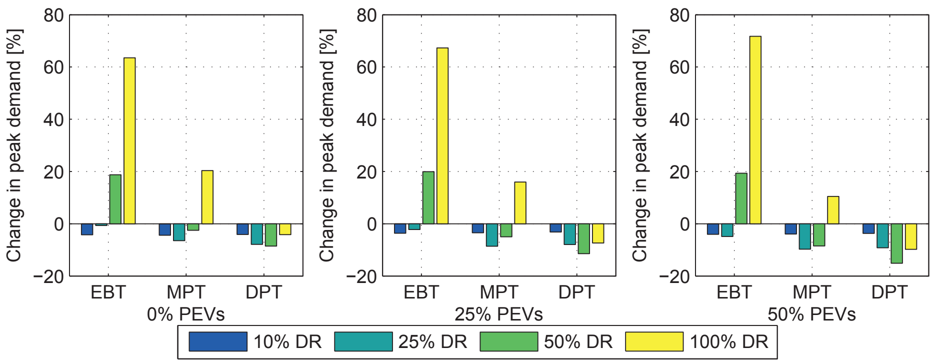


Figure 4.8: Relative change in peak demand for different levels of price-responsive customers and PEV shares.

- **With DPT**, the peak demand would be reduced even if all customers would be price-responsive. If 50% of the customers was responsive and 50% of the vehicles was PEVs, the peak demand could be reduced by as much as 15%, as compared to the case without any responsive customers.

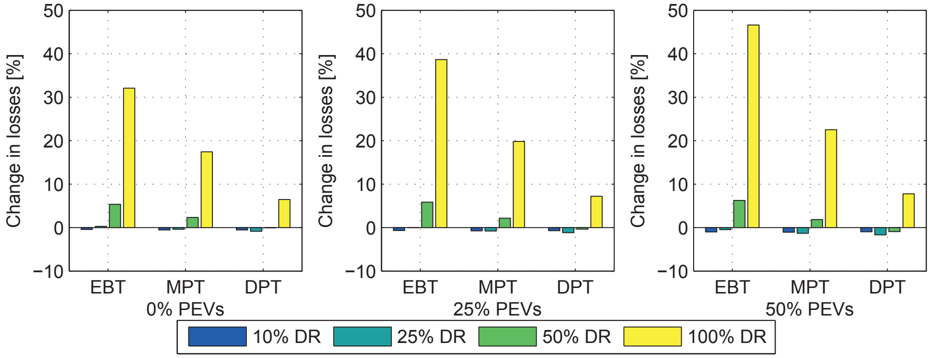


Figure 4.9: Relative change in losses for different tariffs, DR shares and PEV shares compared with the case without any responsive customers.

4.2.2.2 Effects on the active power losses

The active power losses in the 400 V grid are presented in Fig. 4.9 for the different network tariffs and PEV shares. As can be seen, the losses increase rapidly if more than 50% of the customers were responsive for the case with EBT, which is in accordance with the changes in the peak demand. However, for the case with MPT and 50% responsive customers, the losses increase although the peak demand has decreased. One reason for this could be due to the changes in the load duration curve. Although all customers are scheduling their demand to reduce their peak demand, they are scheduling their loads to the same period, resulting in an increased coincident factor. Furthermore, the loads are not only scheduled away from the peak demand period but, as shown in Fig. 4.7, also from hours with high electricity rates. With DPT, the losses were found to be decreased if up to 50% of the customers were responsive.

4.2.2.3 Effects on voltage variations

According to the national grid codes, the voltages should stay within $\pm$ 10% of the nominal voltage under normal operations [107]. The steady state voltage magnitudes in the 10 kV system stayed within these levels in all the simulated cases. Fig. 4.10 presents the number of buses and hours with voltages below different levels (i.e. 85-95% of nominal voltage) in the 400 V grid. As can be seen, the voltage magnitude was found to be below 90% of the nominal voltage if all customers were responsive and EBT or MPT was used, and for the case with EBT, if 50% of the customers were responsive and 50% of the cars were replaced with PEVs. For DPT, the voltage stayed above 90% of the nominal for all cases.

4.2.2.4 Effects on cable loading

With increased peak demand the cables within the distribution system would experience increased loading conditions. However, although the loading increases, no cables would experience any overloading in the 10 kV grid for the simulated cases. In the 400 V grid, at least one cable would be overloaded if all customers would be responsive under the EBT, while no overloading were observed for the

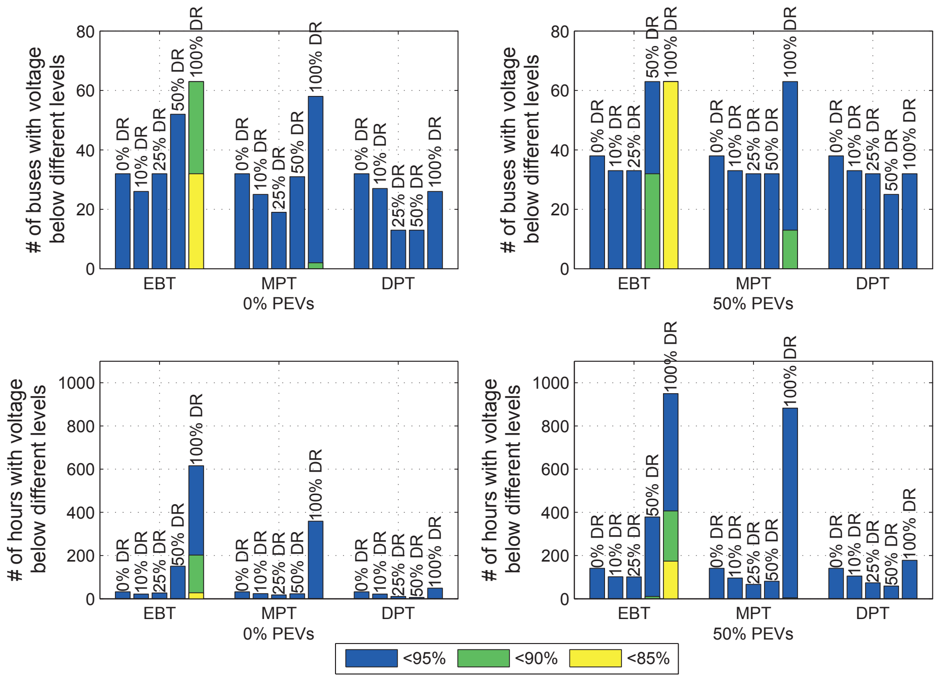


Figure 4.10: Number of buses and number of hours with voltages below different levels (i.e. 85-95% of the nominal voltage), for the different tariffs and PEV shares.

case with MPT or DPT. With 50% of the cars replaced by PEVs, one cable would be overloaded even for the case with 50% of the customers responsive under the EBT.

4.2.2.5 Impacts on transformer loading

Fig. 4.11 presents the number of transformers loaded above different loading levels, and the number of hours with any transformer loaded above these levels. With the estimated load profile, three transformers were found overloaded for 20 hours even in the case without any price-responsive customers. From the figure, the following results can be drawn:

- **With EBT**, both transformer loading and number of overloaded hours increases if 50% of the customers would be price-responsive. With up to 25% of the customer responsive the number of hours with any transformer overloaded would be decreased. With PEVs available, similar results were obtained although the impact is further increased.

- **With MPT**, the transformer loading would be reduced if 25% of the customers would be responsive, while it increases if all customers would be responsive. If 50% of the vehicles would be replaced by PEVs, the number of overloaded transformers decreases even for the case with 50% price-

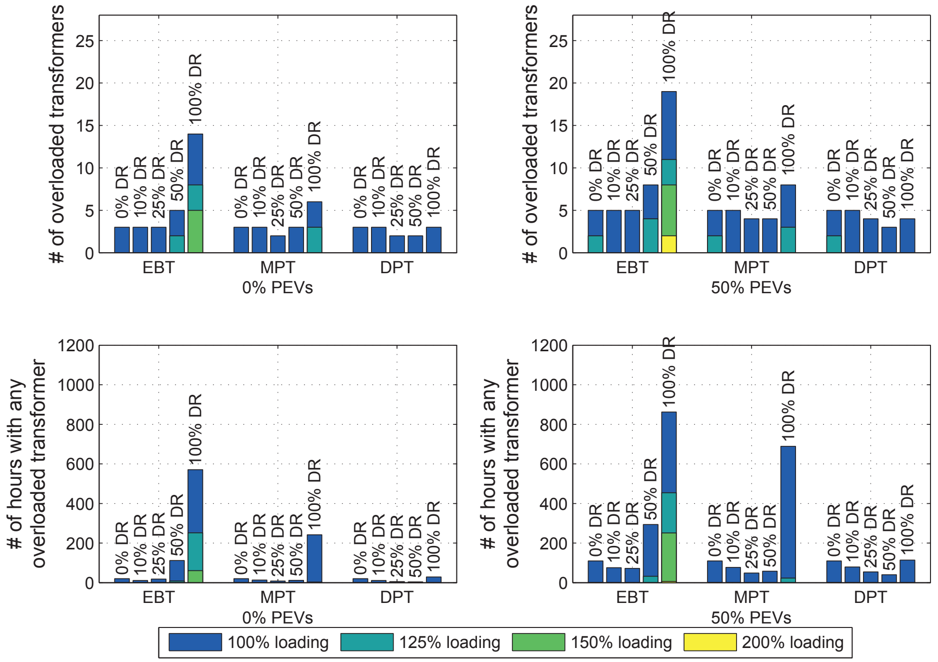


Figure 4.11: Number of transformers loaded above different loading levels and number of hours with any transformer loaded above different loading levels (i.e. 100-200%), for the different tariffs and PEV shares.

responsive customers, compared to the case without any responsive customers.

- **With DPT**, similar results were obtained as for the case with MPT, although all customers could be responsive without increasing the number of overloaded transformers.

4.3 Demand response in system with high shares of wind power

As discussed in Section 2.1, DR could be an effective measure to support the integration of RES. At the same time, RES may increase the volatility in the electricity price which in turn could increase the incentives for customers to schedule their demand. In **paper VII**, the space-heating module of the customer scheduling model was integrated in an electricity market model of the Nordic power market. The aim was to estimate the possible synergy effect between wind power and DR in a future scenario with a high share of wind power in the Nordic power system. This section presents the main findings from **paper VII** and a wider discussion on the results from the study.

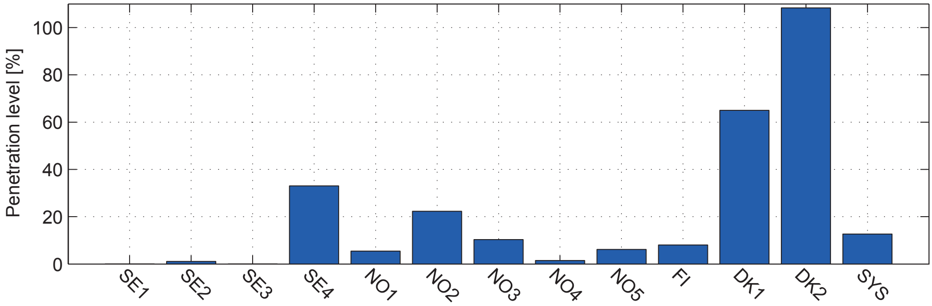


Figure 4.12: Feasible wind power penetration levels for each area and for the total system.

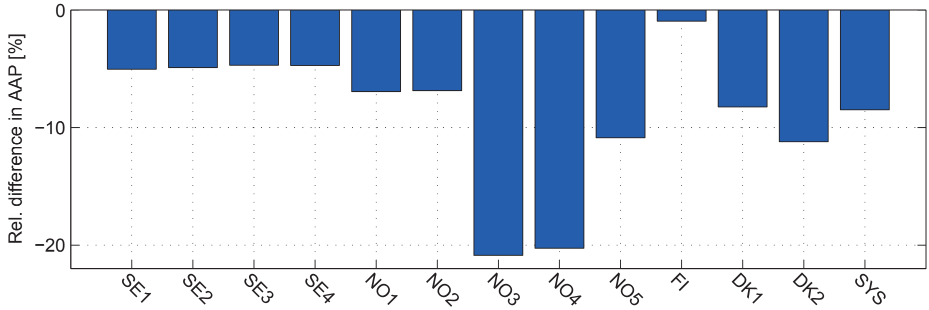


Figure 4.13: Relative difference in AAP due to wind power as compared with the case without any new wind power.

4.3.1 Installed wind power capacity

The wind power distribution and penetration level were estimated based on the possible annual revenue for the wind power producers, which depends on both the available wind resources and the market price within the area. Fig. 4.12 presents the wind power allocation between the different price areas within the Nordic power market. As can be seen, the investment in wind power is mainly located in Denmark and the southern part of Sweden, although investments in wind power are found in most areas.

4.3.2 Effects on the average area price

As the wind power penetration increases, the area prices are generally decreased, due to the additional production of low cost electricity. Fig. 4.13 presents the relative difference in average area price (AAP) for every price area simulated. As can be seen, the highest reduction is observed in NO3-NO5, although the investments in wind power are relatively low in these areas. This shows the importance of including neighbouring price-areas when investigating the effects of wind power on the power market.

The difference in AAP for the case with DR is presented in Fig. 4.14. As can be seen, without wind power the AAP is generally decreased, although the

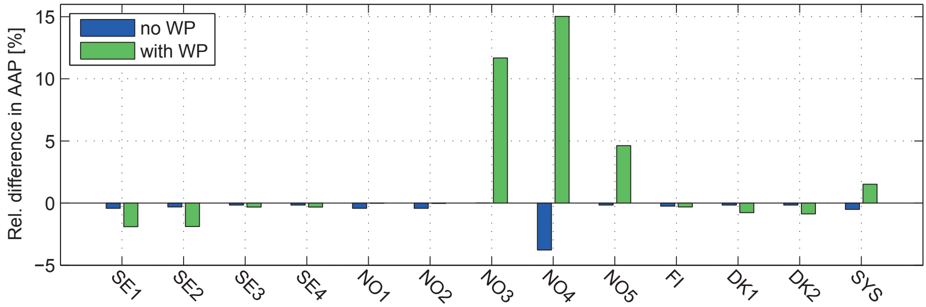


Figure 4.14: Relative difference in AAP with DR as compared with the case without DR, for the case with and without new wind power investments.

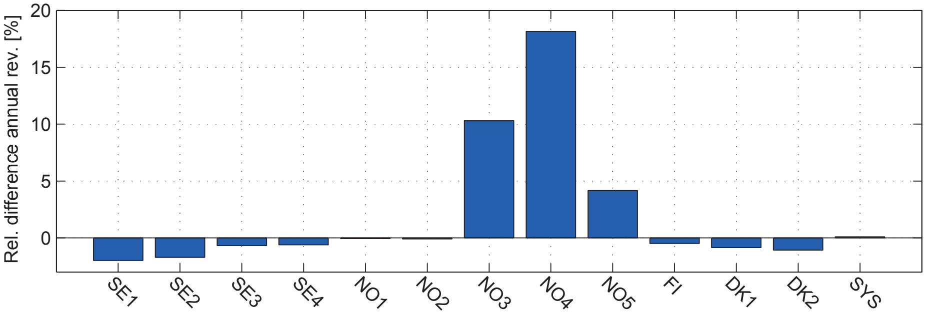


Figure 4.15: Relative difference in annual revenue for wind power producers for the case with DR compared with the case without DR.

difference is small. However, with wind power, the AAP could be increased by up to 15% for some areas in Norway. One possible reason for this could be that the demand is scheduled to reduce the price difference between market areas and thereby reduce the total system cost, which is the objective of the market model.

4.3.3 Benefits for wind power producers in systems with DR

Regarding the revenue for wind power producers, the results indicate that for several areas, the revenue for wind power producers could be reduced when DR is applied. This can be seen in Fig. 4.15, which presents the relative difference in revenue for wind power producers in the different areas. As can be seen, the revenue is only increased for NO3-NO5, that is, the areas with increased AAP due to the DR. The revenue could be decreased by up to 2% as compared to the case without DR. A possible reason for this could be that the demand is shifted such that the exported electricity from area NO3-NO5 is increased, resulting in lower prices for the neighbouring areas and increased prices for these areas. On a system level, the total revenue for all wind power producers was found to be slightly increased.

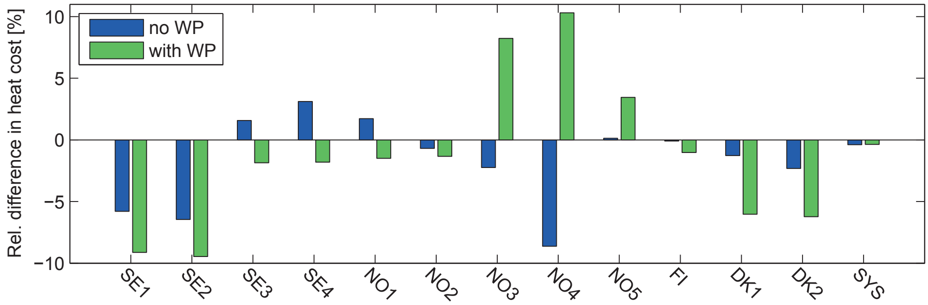


Figure 4.16: Relative difference in annual heating cost for the case with DR as compared to the case without DR, for the case with and without new wind power investments.

4.3.4 Benefits for price-responsive customers' in system with high wind power shares

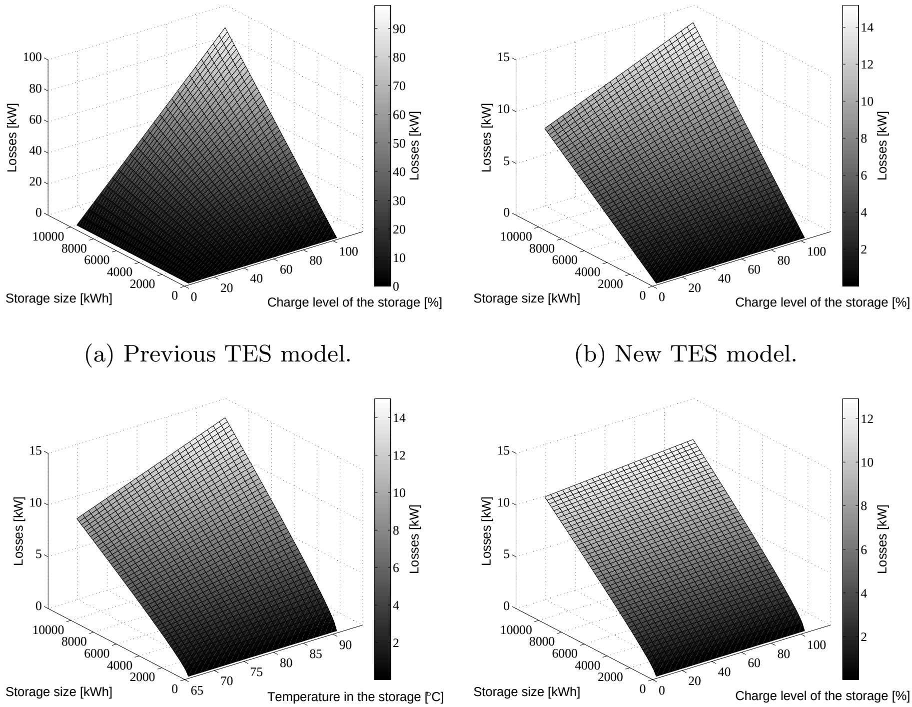
The relative difference in heating cost is presented in Fig. 4.16 for the case with and without wind power investments. As can be seen, the difference varies between the price areas. The cost for heating is generally decreased when DR is applied. However, for some areas the cost is actually increased. One reason for this could be that, since all areas are interconnected, changes in demand in one area affect the price in another. Hence, customers in i.e. NO4, could experience an even higher increase in heating cost if they did not schedule their heat demand. On a system level, the reduction in heating cost remains at the same levels when wind power is available, as compared to the case without wind power.

4.4 Investments in TES

This section presents the main findings from **paper VIII** which proposes an new TES model for the MILP based investment decision tool, DER-CAM.

The main benefit of the new TES model proposed in **paper VIII** relates to the thermal loss calculation and the possibility to use the storage in combination with both low and high temperature energy sources. Fig. 4.17 presents the losses calculated by the previous version of the TES model (Fig. 4.17a) and by the new TES model (Fig. 4.17b) together with the losses calculated for a fully mixed TES (Fig. 4.17c) and an ideal stratified TES (Fig. 4.17d). As can be seen the new TES model calculates the thermal losses more accurately compared to the previous TES model.

The new TES model was used to assess the optimal investments for three different building types in two cities in California; San Diego and San Francisco. From the economic point of view, investments in TES were found less attractive compared to investments in other technologies, hence no TES were adopted. From a CO_2 perspective, investments in TES were more beneficial although the TES adoption was generally decreased with the new TES model compared with the previous TES model. With the possibility to invest in HP, the new model results in higher TES adoption for San Diego, while the adoption was reduced for build-



(a) Previous TES model. (b) New TES model.

(c) Fully mixed TES. (d) Ideal stratified TES.

Figure 4.17: Calculated losses for the previous (a) and new (b) TES model and for a fully mixed (c) and ideal stratified (d) TES.

ings in San Francisco. Furthermore, for all buildings, only low temperature TES was adopted. This could be due to the higher losses associated with the high temperature storage section. Although there is a large variation in technology selection between the case with the new TES model compared with the previous TES model, the CO_2 emission stayed very stable for most buildings, indicating a large and nearly flat solution space.

Regarding the utilization of the TES, Fig. 4.18 presents the dispatch and losses for a 2000 kWh TES for both models. As can be seen, with both models, the TES would be utilized similarly although, with the new model, the heat was stored for a longer period. The reason for this could be due to the low dependency of the charge level in the new model. On an annual basis, the losses contribute to roughly 2% of the energy taken from the TES when the new model was used while the losses estimated by the previous model would be about 7%. A possible reason for the large difference in losses could be due to that only low temperature storage has been adopted in the new model.

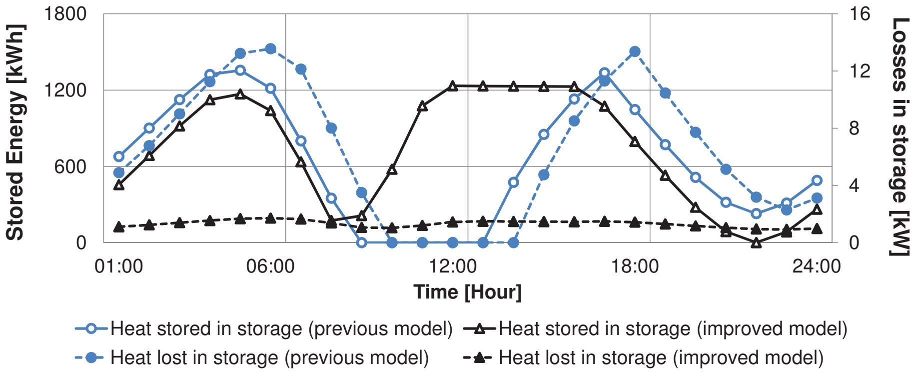


Figure 4.18: Energy stored in the TES and the estimated storage losses for both TES models for a large hotel building in San Diego for a weekday in March.

Chapter 5

Conclusions and future work

5.1 Conclusions

The aim of this thesis was to investigate the effects of PEVs and DR on distribution systems in Sweden. In addition, the possible synergy effects between wind power and DR has been examined, as well as the possible benefits of TES in commercial buildings in California. From the study, the following conclusions can be drawn:

- **High shares of PEVs could result in overloading of components in the distribution system although there are large differences between distribution systems.**
  The residential distribution system investigated experience issues such as transformer and cable overloading even without any PEVs. The commercial area investigated could, on the other hand, handle 100% PEVs without any overloading, even if charging at work would be possible.

- **By scheduling the charging of PEVs the impact could be reduced, but the incentives need to be designed carefully.**
  If the charging of PEVs was scheduled in order to reduce the system losses all vehicles could be replaced by PEVs without increasing the peak demand, even in the residential distribution system. However, if hourly electricity tariffs based on the day-ahead market were used as price signals, only 24% could be hosted without increased peak demand in the residential distribution system. By scheduling other flexible loads in order to reduce the system losses, the variations in demand could be further reduced.

- **Using the day-ahead prices as incentives for customers to schedule their loads may increase the impact on the distribution systems.**
  By giving all customers the same price signals, they could schedule their loads to the same hours resulting in increased coincident factor and increased peak demand. However, by combining the day-ahead prices with a power based network tariff, an increased peak demand in the distribution system could be avoided.

- **Power based network tariffs could increase the customers' incentives to schedule their demand.**
  For customers with PEVs or low space-heating demand the possible cost saving would increase with a power based network tariff, although the difference decreases for customers with a high load factor, i.e. small variations in their demand.

- **Wind power producers could experience reduced profit if DR is applied.**
  If the customers scheduled their space-heating in order to reduce the total system cost, the profit for wind power producers could be decreased. On the other hand, the possible benefit for customers scheduling their demand would generally increase, although the heating cost could be increased for some areas.

- **The modelling approach used for TES in DER-CAM would affect investment decisions.**
  By modelling the losses from a TES in greater detail, more reliable investment decisions could be made. For the simulated buildings, the investment decision would differ depending on the TES modelling approach, although the goal function would remain relatively constant. Independent of the modelling approach, from an economic point of view, TES was found to be less attractive compared with other investment options in commercial buildings in California.

5.2 Future work

The impact of PEVs varied largely between the investigated areas. However, an approximate approach was used in this thesis, where charge time was based on average driving distances and the distribution of the PEVs were based on the demand in the node of the distribution system. To assess how these parameters would affect the result, Monte Carlo simulations could be an interesting form of continuation in order to obtain a range of possible effects on the distribution system. Moreover, due to the relatively low regulating prices on the Nordic power market, V2G has not been considered in this study. With additional investments in intermittent power generation this could change, and using PEVs for V2G could become more attractive.

Increasing shares of distributed generation, such as solar PV, will pose additional challenges for the distribution systems. In this thesis the influences of distributed generation has not been considered. An interesting continuation of this project could be to investigate how DR could provide support for power systems with high shares of distributed generation.

Although DR have the potential to reduce the stress on distribution systems, the results from this thesis indicate that the distribution system could be negatively affected if a large share of customers become responsive, under an hourly electricity tariff based on the day-ahead prices. Even if the DSO in Gothenburg only provides one power subscription, i.e. a 63 A subscription, it is common that a DSO offers several power subscriptions. To study the impact of different power subscriptions would be interesting.

To avoid increased peak demand within the distribution system, the DSO could introduce power based network tariffs. However, this would only aid the system to certain extent, and it is not sure to what extent this would support integration of renewable energy sources. There are two interesting alternatives that could improve the system utilization further; one, instead of using the day-ahead spot market, the customer could be subjected to the intraday market price instead, two, providing the flexibility to an aggregator that could bid the customers flexibility into the market.

In this thesis, the base load, i.e. the inflexible demand, was assumed to be known. If the base load would differ from the predicted demand, there might be a need to reschedule the flexible demand. For this, a model based on the rolling horizon approach could be an interesting alternative. Furthermore, to implement the scheduling model into a building would be of great importance in verifying the model.

The market model used to assess the synergy between wind power and DR does not consider any start-up cost or maximum ramping rates for the considered generation units. By including such constraints it would better reflect a real power market. Furthermore, all generation units within one area are assumed to generate electricity at the same price depending on the generation technology, e.g. hydro, coal or nuclear. Hence the number of price levels in the price curve would be limited. This could in turn result in an underestimated impact of DR on the market price. An interesting continuation could be to develop the market model further to include variations in the generation cost for a given technology within one area. It could also be interesting to include other flexible loads as well, e.g. PEVs, into the market model.

The TES model developed for DER-CAM was only focusing on the TES itself. However, by considering the effects on the units connected to the TES more realistic results could be obtained. A continuation regarding this model could be to investigate the influences of the TES on the units connected to the TES.

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Appendix A

Data used in the case studies

Most of the data used throughout this thesis is presented in the appended papers. However, this chapter presents some of the data that has been used but not fully described in the papers due to space limitations.

A.1 Electrical distribution system in Gothenburg

There are four power plants within Gothenburg supplying the demand in the city with the largest plant, Rya Verket, supplying about 30% of the electricity consumed in Gothenburg [108]. The electricity demand that is not covered by the production within Gothenburg is imported through five feed-in points. In total, there are about 18 130/10 kV transformer stations in the distribution system which is mainly composed of underground cables. The voltage levels are mostly 10 kV and 400 V, although other voltage levels exist, such as 20 kV and 50 kV. The 10 kV distribution system is designed as an OLR-DS, which allows the DSO, Göteborg Energi, to operate the distribution system with a high reliability since the supply could be restored by topology changes in case of failure in any of the feeders. At the customer site the voltage level is 400 V. However, some of the large industrial customers are connected directly to the 10 kV distribution system.

In the case studies two parts of the distribution system, i.e. a commercial and a residential area, have been investigated. The structure of the distribution grid is presented in **paper I** and **paper III**. However, in **paper I**, only one feeder in the residential 400 V grid were modelled in detail. In **paper VI**, one additional feeder was modelled which is presented in Fig. A.1.

Since no measurement of reactive power was available for the investigated areas, a constant power factor of 0.95 lagging has been considered in all appended papers.

A.2 Flexible demand

To assess the potential for demand response, data from a measurement project has been used in **papers IV-VI**. The measurement project was conducted by the Swedish Energy Agency, and monitored the electricity usage for different appliances in 400 Swedish households. The majority of the households were monitored

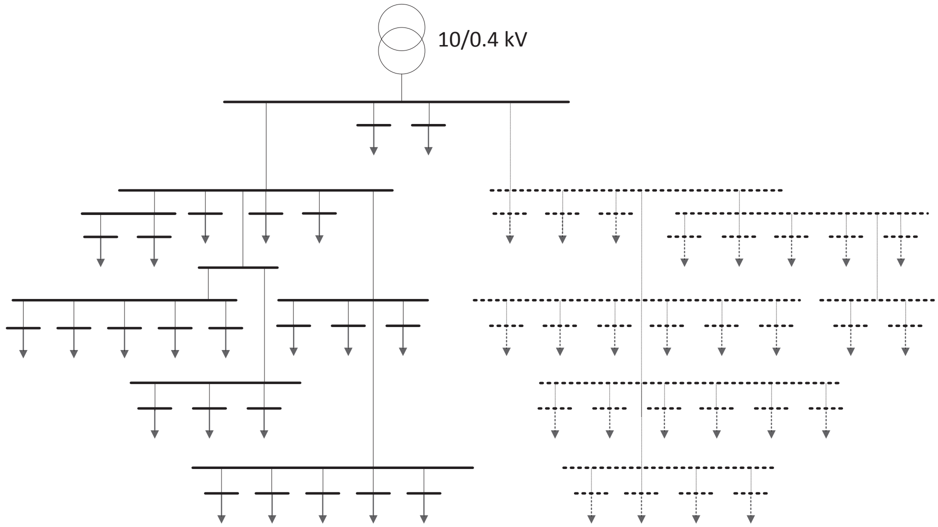

Figure A.1: 400 V grid in a residential area in Gothenburg. The dashed lines represent the additional feeder simulated in **paper VI**.

for one month, while some were monitored for one year. Data from up to 20 of the households monitored for one year have been used in this thesis. From the data the non-flexible base load and domestic hot water load were directly extracted, while for dishwasher, laundry and drying machines the start times for each cycle were extracted. Although some appliances could be used more than once for some days, only one cycle has been considered flexible. Furthermore, an average cycle consumption of 0.8 kWh has been assumed for dishwashers and laundry machines, and 1.4 kWh for clothes dryer, which is in line with the measurements [109].

Regarding electricity used for space-heating, the average share of the electricity consumption used for space-heating was found for the customers measured during the winter period. In **paper IV**, this share was used to estimate an aggregated heat demand for the investigated distribution system. However, since the outdoor temperature varies between the location of the measurement and the investigated distribution system, another approach was used to estimate the electricity used for space-heating in **papers V-VI**. In these papers, the space-heating demand was estimated based on the outdoor temperature and different building parameters. In **paper VI** the building parameters were based on a 125 m^2 detached house with a concrete slab, presented in [110], with different isolation and ventilation parameters. The annual heat demand for the different building types varied from 5500 to 24000 kWh/year.

Fig. A.2 presents the load profile for one summer and one winter week for one of the households investigated in this study. As can be seen, for this house, a large share of the electricity consumption is used for space-heating during the winter week. During the summer period, the heat demand is low and the electricity is mostly used for other purposes, such as domestic hot water and base load.

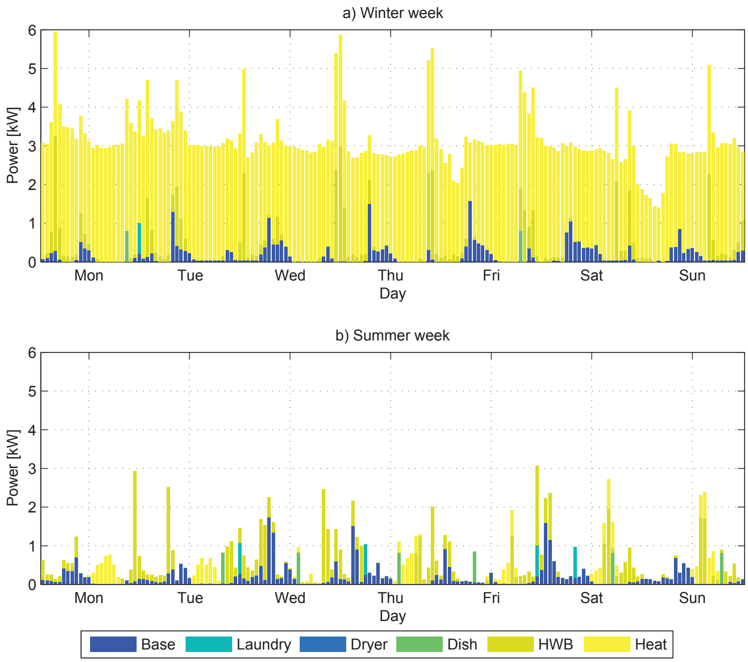

Figure A.2: Weekly load profile for one of the customers, for a winter week (a) and a summer week (b).

A.3 Vehicle usage data

To obtain realistic charging scenarios data from a national travel survey has been used in this thesis. In **paper III** the vehicle usage pattern was presented for weekdays. However, Fig. 2 in that paper was incorrect and did not show the distribution of the stop times. The correct figure is presented in Fig. A.3.

Since the simulations were conducted on an annual basis in **paper VI**, the usage pattern for weekends has been considered. Fig. A.4 presents the start and stop times for journeys conducted during weekends.

A.4 Electricity market data

To model the Nordic day-ahead market Elspot, data regarding generation cost and capacities are vital. In this thesis the generation costs have been estimated based on [111], while the generation capacities are based on data from [11, 112–115].

Fig. A.5 presents the aggregated marginal supply curve used in the study of the Nordic power market excluding the wind power generation, which is assumed to bid a zero price. Furthermore, the energy produced by hydro power is limited to the available water which would vary with the season. To cope with this, monthly electricity production data from 2012 has been considered. The annual electricity produced from hydro power was 79.5 TWh in Sweden, 142.9 TWh in Norway and 16.6 TWh in Finland. Fig. A.6 presents the yearly distribution of the electricity produced from hydro power as a percentage of the annual electricity

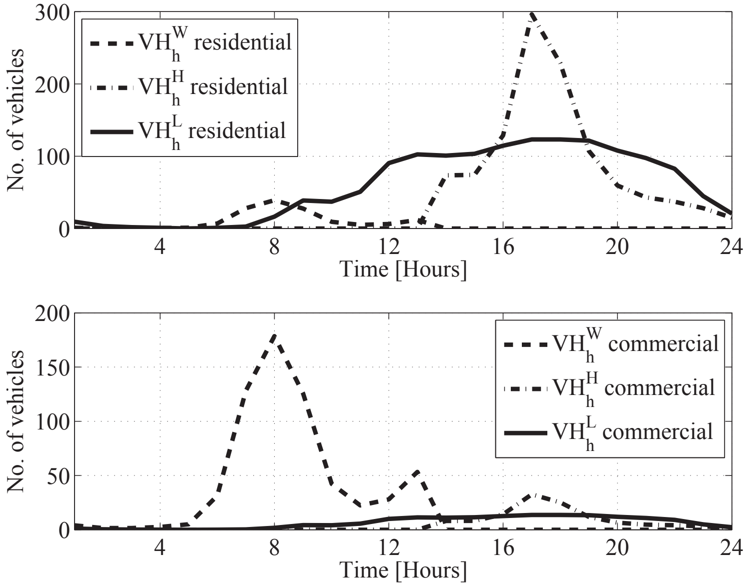

Figure A.3: Distribution of the stop times for a residential and a commercial area. VH^W represent journeys to work, VH^H represent journeys to home, VH^L represent other journeys.

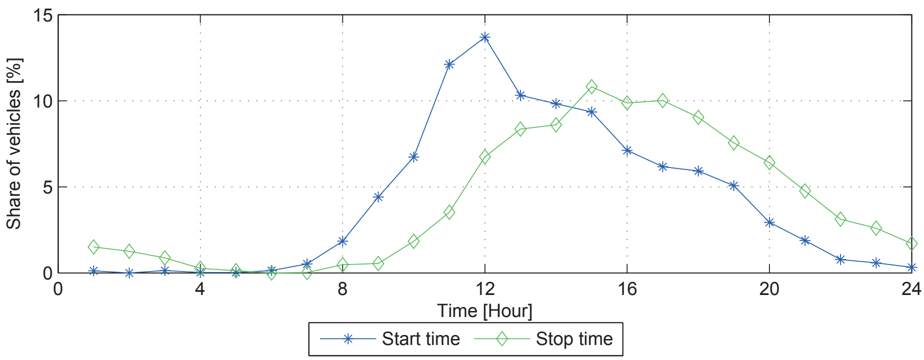

Figure A.4: Start and stop times for journeys conducted during weekends.

produced by hydro power in each country.

The maximum transmission capacity between the price areas was assumed by considering the maximum net transfer capacity (NTC), which can be found in [11]. Table A.1 presents the NTC values for the Nordic region.

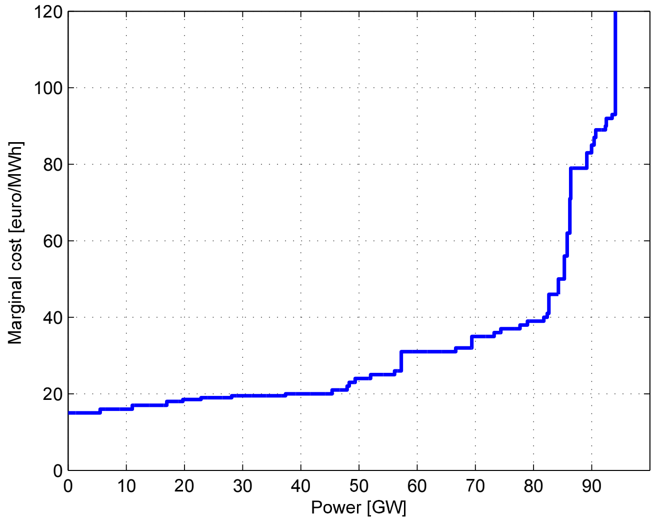

Figure A.5: Aggregated marginal supply curve estimated for the Nordic power system.

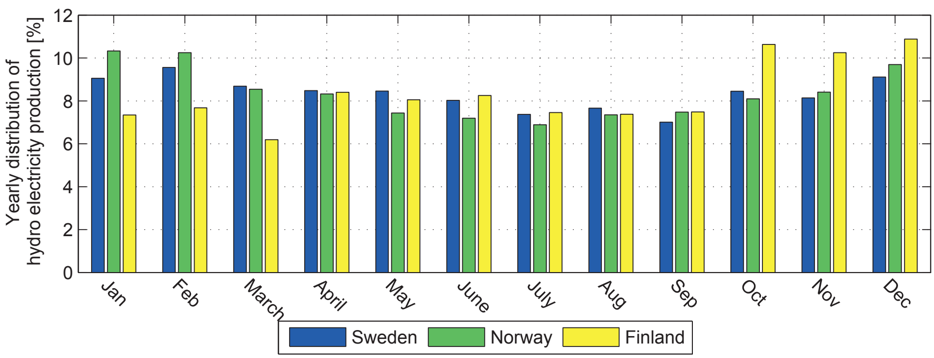

Figure A.6: Yearly distribution of the electricity produced from hydro power.

Table A.1: Maximum net transfer capacity for the Nordic region

	SE12	SE2	SE3	SE4	NO1	NO2	NO3	NO4	NO5	FI	DK1	DK2
SE1		3300						600		1500		
SE1		3300						600		1500		
SE2	3300		7300				1000	300				
SE3		7300		5300	2095					1350	680	
SE4			2000									1300
NO1			2145			2200	500	300				
NO2					3200				500		1000	
NO3		600			500							
NO4	700	250					1000					
NO5					3500	600						
FI	1100		1350									
DK1			740			1000						590
DK2				1700							600	